COGENERATION POTENTIAL IN ONTARIO
And Barriers to its Development

Prepared for the
Ontario Ministry of Energy
By

Acres International Limited
February, 1987

Ontario
Ministry
of
Energy
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87-06192/

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EXECUTIVE SUMMARY

A review of cogeneration technologies as well as their existing and possible applications in Ontario has been carried out. The results of that review indicate that there currently exists over 400 MW of cogeneration in Ontario and suggests that there is significant additional cogeneration potential in the province. Table S.1 lists estimated demand for high temperature heat in the industrial, institutional, commercial and residential sectors and relates this demand to the technically achievable electrical output from cogeneration schemes. As shown in the table, a potential for almost 10 000 MW of electricity generation from cogeneration is technically possible. Not all of this, however, will be economic.

In addition to the estimate of the technical potential for cogeneration, estimates were made of the amount that could be economic by 2000 (assuming a perfect market exists) and the amount that is likely to have been implemented by 2000 (recognizing that a perfect market for cogeneration does not exist). These estimates, by economic sector and subsector, are presented in Table S.2. Using the base case energy price and economic growth projections published by the Ontario Ministry of Energy in 1985, the total economic potential for cogeneration in Ontario exceeds 3800 MW. Because of a variety of institutional, financial and information barriers, it is estimated that of this only 1300 MW will be developed by 2000 unless existing barriers to the development of cogeneration are removed or reduced. All of this 1300 MW likely additional development is in the industrial sector.

The amount of cogeneration which is likely to be developed is affected by future natural gas prices, future electricity prices, and technology changes, as well as future utility and government policy initiatives. Estimates for the total amount of cogeneration which might be economic were made for a number of scenarios.

TABLE S.1

ESTIMATE OF TECHNICAL POTENTIAL FOR COGENERATION

	Heat Demand Category								
	Low (< 25,000 #/hr)			Medium (25,000 to 100,000 #/hr)			High (> 100,000 #/hr)		
Sector & Subsector	Cogen System	Total Steam Demand (000#/hr)	Assoc Power (MW)	Cogen System	Total Steam Demand (000#/hr)	Assoc Power (MW)	Cogen System	Total Steam Demand (000#/hr)	Assoc Power (MW)
Industrial									
Pulp & Paper	STW	914	16	STW	1,838	32	STW	16,966	385
Iron & Steel	GT	118	6	GT	338	18	GT	8,216	426
Smelting & Ref	GT	242	13	GT	788	41	GT	3,000	156
Petroleum Prod	GT	77	4	GT	113	6	GT	11,093	575
Chemicals	GT	637	33	GT	1,838	95	GT	8,277	429
Other Mfg	GT	4,921	255	GT	7,763	403	GT	17,000	882
Total		6,908	327		12,675	594		64,551	2,853
Institutional									
Universities	N/A	-	-	ST	540	59	STD	1,014	87
Hospitals	D	795	141	D	1,248	215	N/A	-	-
Total		795	141		1,788	273		1,014	87
Commercial									
Shopping Malls	D	4,050	342	GT	3,635	307	N/A	-	-
Offices	D	10,321	682	D	6,886	455	N/A	-	-
Total		14,371	1,024		10,521	762			
Residential									
Apartments	D	52,029	3,902	N/A	-	-	N/A	-	-
TOTAL		74,103	5,394		24,984	1,629		65,565	2,940

TOTAL TECHNICAL POTENTIAL: 9,962 MW

ST - Steam Tubine
STD - Steam Turbine with Supplemental Diesel
STW - Steam Turbine (with wood waste)
GT - Gas Turbine
D - Diesel
N/A - No technical potential indicated.

TABLE S.2

TOTAL COGENERATION POTENTIAL

(Base Case - Wood/Gas Fuel Option and Base Case Prices)

Sector Sub-Sector	Heat Demand Category	---- Total Cogeneration Potential ----- Economic (MW)	Financial (MW)	Implementation (MW)
Industrial				
- Pulp & Paper	Low	5	0	0
	Medium	8	8	0
	High	385	385	301
- Iron & Steel	High	178	160	106
- Mining & Smelting	High	57	37	37
- Petroleum Product	High	231	231	194
- Chemicals	High	263	244	218
- All Other	Low	0	0	0
	Medium	460	460	460
	High	356	133	30
TOTAL INDUSTRIAL		1942	1659	1347
Institutional				
- Universities	Medium	14	0	0
	High	18	18	0
- Hospitals	Medium	78	0	0
TOTAL INSTITUTIONAL		110	18	0
Commercial				
- Shopping Malls	Medium	0	0	0
- Offices	Medium	459	0	0
TOTAL COMMERCIAL		459	0	0
Residential				
- Apartments	Low	1322	0	0
TOTAL RESIDENTIAL		1322	0	0
TOTAL ALL SECTORS		3833	1677	1347

It was found that better data is needed to make a reliable estimate of the potential for cogeneration in the commercial sector. Work is in progress in the United States and elsewhere to develop cogeneration systems for this sector, and additional work is needed to further define the relevant heat loads, cogeneration potential and barriers to harnessing this potential.

1 - INTRODUCTION

COGENERATION POTENTIAL IN ONTARIO

1 - INTRODUCTION

1.1 - Background and Objectives

Cogeneration is the simultaneous production of useful heat and mechanical energy or electricity. Though it is used widely in several countries, it has seen limited use in Ontario. A 1977 study for the Royal Commission on Electric Power Planning estimated a total installed capacity of 510 MW*, and a more recent estimate puts the figure at 400 MW**. Four hundred megawatts represents approximately 2% of the total capacity of the Ontario Hydro system. No major industrial cogeneration facilities have been commissioned in the nearly 10 years since the 1977 survey was undertaken. In the institutional sector, two universities have installed cogeneration. This relative lack of activity is in contrast with recent studies of cogeneration pointing to significantly greater potential in the Province.

The current study is intended to assess the potential for cogeneration in the industrial, commercial, institutional and residential sectors, to describe the barriers that have impeded the realization of this potential and to assess the impacts of measures to encourage the implementation of economically sound cogeneration projects.

---

* Leighton and Kidd (1977).

**Shalaby (1986).

1.2 - Report Organization

In the following sections, we present the framework for analysis (Section 1.3), definitions of the various types of cogeneration potential (Section 1.4), and a summary of earlier estimates of potential (Section 1.5).

The technical potential for cogeneration is discussed in Chapter 2. Following a description of the various technologies for cogeneration, estimates are provided for the technical limits to cogeneration, by sector and in total, including an identification of the most promising technology(ies) for each market segment. The chapter concludes with a description of the technical data base, including sectoral case studies which form the basis of estimating economic, financial and implementation potentials.

The assessments of economic, financial and implementation potentials are contained in Chapters 3, 4 and 5 respectively. Each chapter begins with a description of the approach and the economic or financial analytic parameters used in the analysis. The results of the case study evaluations are then presented, followed by an aggregation from the case-study level to the total industrial, institutional, commercial and residential sectors.

In Chapter 6, we turn to the barriers that have prevented the realization of cogeneration opportunities in Ontario. Several types of barriers are identified and described, based on earlier studies and insights gained from interviews held with selected interested organizations. Possible means of modifying these barriers are also discussed.

Impact analyses including alternative external factors and provincial policy measures are shown in Chapter 7. Impacts are measured in terms of the increased potential for cogeneration under each of six pricing and policy scenarios.

Appendix A contains a review of earlier studies of cogeneration potential. The case studies underlying the current estimates of potential are described in Appendix B. Appendix C presents details of the project-specific economic and financial analysis. Finally, Appendix D provides the results of the interview survey designed to identify barriers to cogeneration development.

1.3 - Framework for Analysis

The assessment of cogeneration potential considered applications in four principal sectors: industrial, institutional, commercial and residential. Each sector was further categorized on the basis of the level of process heat demand and on readily identifiable demand subsectors. The overall framework for the analysis is summarized in Table 1.1. The three levels of process heat demand used in the industrial sector, (i.e. low: less than 25 000 lb/h, medium: 25 000 to 100 000 lb/h, and high: greater than 100 000 lb/h), were developed from earlier studies (Leighton and Kidd, 1977 and Acres Shawinigan, 1979). This breakdown was also adopted for the other sectors to ensure that the definition of low, medium and high heat demand categories remained consistent throughout the report.

Industrial

A 1983 summary of boiler registrations for the Province of Ontario was reviewed to identify the capacity and industrial distribution of boiler installations. The six industrial subsectors listed in Table 1.1 represent 66% of the total boiler capacity in the Province and nearly 40% of the total number of boilers. To coordinate the boiler data with the requirements of the current study, the boilers

TABLE 1.1

FRAMEWORK FOR THE ESTIMATION OF TECHNICAL POTENTIAL

Sector & Subsector	Heat Demand Category								
	Low (< 25,000 #/hr)			Medium (25,000 to 100,000 #/hr)			High (> 100,000 #/hr)		
	Cogen System	Total Steam Demand (000#/hr)	Assoc Power (MW)	Cogen System	Total Steam Demand (000#/hr)	Assoc Power (MW)	Cogen System	Total Steam Demand (000#/hr)	Assoc Power (MW)
Industrial									
Pulp & Paper									
Iron & Steel									
Smelting & Ref									
Petroleum Prod									
Chemicals									
Other Mfg									
Total									
Institutional									
Universities									
Hospitals									
Total									
Commercial									
Shopping Malls									
Offices									
Total									
Residential									
Apartments									
TOTAL									

TOTAL TECHNICAL POTENTIAL:

ST - Steam Tubine
STD - Steam Turbine with Supplemental Diesel
STW - Steam Turbine (with wood waste)
GT - Gas Turbine
D - Diesel
N/A - No technical potential indicated.

were aggregated into the high, medium or low heat category based on their capacity in pounds per hour. Over 60% of the boilers fall into the low heat demand category, while boiler plants in the high demand category represent about 80% of total steam capacity.

Institutional
(Universities and Hospitals)

On the basis of the survey data in an earlier study*, the 15 universities in Ontario are classified in the high heat demand category if their listed steam requirement exceeds 150 000 lb/h. Six universities fulfill this requirement; the remaining nine universities are in the medium demand category.

Ministry of Health records for Group 1 to 6 Acute Treatment Public General Hospitals were used to assemble the heat demand categories. The medium heat demand category was defined as those hospitals with 400 or more beds, while low heat demand hospitals have 100 to 399 beds. Approximately 50% of the public hospitals in Ontario are included within these two categories. While no hospitals had a sufficient heat demand to be included within the high heat demand category, 39 are defined as medium heat demand and 68 as low heat demand.

Commercial
(Large Shopping Malls and Office Space)

Both shopping malls and office space are enumerated in terms of gross floor area for specific geographic regions within the Province.**

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[*] Leighton and Kidd (1977).

[**] Metropolitan Toronto Planning Department, Retailing in Regional Municipalities, 1983 and Royal LePage, Commercial Real Estate Services Database, 1986.

Shopping malls, a classification which excludes strip malls and individual outlets, are part of the medium heat demand category if the gross retail floor area exceeds 23 000 m2 (250 000 ft2). All other malls fall into the low heat demand category. Rental office space, which includes government offices, 100% owner-occupied buildings and medical office buildings is similarly classified. The medium heat demand category is defined as buildings in which the gross rentable floor space exceeds 250 000 m^2. All other buildings in the data base are in the low heat demand category. The data base does not include office buildings of less than 1900 m^2 (20 000 ft^2).

Residential

The residential sector is defined to include large rental housing buildings exceeding 20 units.* This definition includes 60% of the housing units listed in the data base. All buildings fall within the low heat demand category.

1.4 - Defining the Potentials for Cogeneration

The total potential for cogeneration is defined, in descending order of magnitude, at four levels of feasibility: technical, economic, financial and implementation.

The point of departure for the study is the identification of those sites that may have the physical or technological capability to produce cogenerated energy. The selection of the appropriate process (diesel, gas turbine, high-pressure boiler and steam turbine, etc) is firstly a technical decision, including such considerations as heat to power ratios, operating constraints and relative equipment costs. Estimating the technical potential addresses the question: For a given level of process heat, how much electricity can be cogenerated with various technologies? The technical potential is constrained if heat demands have so low a load factor that cogeneration is impractical or if the load is too small for existing technology.

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* Commission of Inquiry into Residential Tenancies, Research Study No. 30, 1986.

A candidate cogeneration application must satisfy at least three criteria beyond technical feasibility to achieve implementation. First, it must demonstrate that the application produces heat and electrical energy at a cost competitive with other supply alternatives. This concept of supply price is used as an indicator of economic feasibility. Second, the application must be financially feasible from the 'narrow' perspective of the potential cogenerator. The financial analysis uses market prices of energy and other commercial data to compute payback periods and return on investment (ROI) as indicators of financial feasibility. These must then be compared to what are considered acceptable payback periods or ROI by the potential cogenerator.

Technical, economic and financial feasibility are necessary but not sufficient conditions to ensure the implementation of cogeneration technology. Implementation requires that additional criteria be satisfied. These may be based on the fact that cogeneration is a 'new business' for the operating entity, or that cogeneration projects are perceived as too risky. As discussed in Chapter 5, the estimates of implementation potential will be based on more stringent payback criteria than those used in estimating financial potentials.

1.5 - Earlier Studies of Cogeneration Potential

Cogeneration potential has been the subject of several studies in Ontario over the past ten years. Reports and estimates that have been made public show a considerable variation in definitions of 'cogeneration potential', research and estimating techniques, and, consequently, numerical results. Some of the studies are difficult to compare as they fail to articulate the type of potential being estimated. Appendix A contains, in chronological order, the principal references and findings. A summary of these estimates is provided in Table 1.2. Several conclusions emerge from the literature review.

(a) Wide Range of Estimates - There is a substantial variation in the estimated potentials for cogeneration. The studies reviewed indicated technical potentials ranging from 1000 to 5000 MW by the year 2000. The economically feasible scope for cogeneration is shown to range from 500 to 1125 MW. Commercial potential varies from 140 to 1800 MW. Estimates of implementation potential range from 150 to 1500 MW.

(b) Wide Range of Study Assumptions and Coverage - An important cause of the differing estimates of potential is the range of assumptions and sectoral coverage adopted by the various studies. These factors pertain to the definitions of economic and other types of potentials and to the breadth of end-use sectors and subsectors being analyzed. More importantly, several of the estimates are ambiguous to the extent that they do not identify the type of potential(s) under consideration.

(c) Lack of Policy Orientation - The differentiation among various types of potentials is of more than academic interest. To cite only one example, the development of public policies and programs is greatly assisted by knowledge of

(i) how much cogeneration is desirable from the perspective of economic efficiency and growth,

(ii) how much cogeneration is likely to occur in a 'do nothing' scenario, and

TABLE 1.2

SUMMARY OF EARLIER ESTIMATES OF COGENERATION POTENTIAL

	Target Year	Additional Potential for Cogeneration by Type of Potential (MW) Technical	Economic	Financial	Implementation
Leighton and Kidd (1977)	1985	3 500 (I)	-	-	1 500 (I)
Ontario Hydro (1978)	2000	2 800 (I)	-	-	-
Acres Shawinigan Ltd (1979)	2000	1 000 (I*)	650 (I*)	375 (I*)	-
Royal Commission (1980)	2000	2 300 (I)	-	400 (I)	-
Cogeneration Associates (1980)	1990	4 600 (I)	-	1 800 (I)	-
Ontario Hydro (1981)	2000	3 300 (I)	-	-	450 (I)
Acres (1982)	2000	575 (I*)	140 (I*)	-	
Diener and Dupont (1984)	2000	1 125 (I*)	385 (I*)	-	
Ministry of Energy (1985)	2000	5 000 (I) 1 000 (I)	500 to	-	-
Ontario Hydro (1985, 1986)	2000	- -	150 to 1 000 (I)	150 to 1 000 (I)	
Select Committee (1986)	2000	- -	-	300 to 1 400 (I)	
Range of Estimates		1 000 to 5 000	500 to 1 125	140 to 1 800	150 to 1 500

I - Industrial
I* - Large Industrial

(iii) how does the Province narrow the gap between (i) and (ii), that is, between the economic and implementation potentials.

(d) Unfulfilled Potential - Eight estimates originated in the period 1977 to 1984. These early estimates projected an implementation potential of 1500 MW by 1985 and financial potentials of 140 to 1800 MW by 2000. Yet in the period 1977 to 1985, no new cogeneration capacity was installed in Ontario. What is behind this discrepancy? The current study aims to answer this question by defining clearly the types of potential being estimated and by analyzing the barriers that cause the financial and implementation potentials to fall below the economic limits to cogeneration.

(e) Data Used - Much of the data behind the analysis is incomplete and somewhat dated. The studies have included little or no data on non-industrial end-use sectors, reflecting a general data deficiency for commercial and residential applications. In the industrial sector, there is generally adequate data; however, it needs updating as the studies continue to reference surveys carried out in the 1976 to 1978 period.

2 - TECHNICAL POTENTIAL

2 - TECHNICAL POTENTIAL

2.1 - Review of Cogeneration Technologies

There are several technologies that can be used for cogeneration. The choice between technologies depends on such factors as the ratio between steam demand and power requirements available fuel sources and level of output. Cogeneration equipment currently in use, or having promise in the near term, includes

- steam turbines,
- gas turbines,
- diesel engines,
- organic Rankine cycles, and
- fuel cells.

The steam turbine is today the option most commonly used in industry and in some institutional applications. The gas turbine is being used increasingly in industry, especially where there is a supply of attractively-priced natural gas. Diesel engines are used mostly in smaller applications - institutional and commercial - though in their larger sizes they have a potential for industrial cogeneration.

The organic Rankine cycle is less common, though several examples exist in the US, while the fuel cell is still in the development stage. It shows promise in the near term for small applications, such as residential or commercial.

A conventional thermal generating station produces electricity with about 35% efficiency. Cycle efficiency can also be expressed as a heat rate, that is, the amount of heat supplied to the boiler as fuel to produce one kilowatt hour. The higher the heat rate, the lower the efficiency. The heat rate in a typical conventional power plant would be in the order of 9000 to 10 000 Btu/kW.h (38 to 34% efficiency). In this case, all heat rejected from the power generating cycle is lost to the environment although it is attributed to the generation of the electricity.

When producing electricity by cogeneration, the heat rejected from the power generating cycle is diverted to some useful purpose such as process or space heating. Only the heat actually consumed in the generation of electricity is attributed to its production. As a result, the heat rate is 4000 to 4200 Btu/kW.h (85 to 81% efficiency). Hence, cogeneration requires less than one half of the fuel used in a conventional generating station to generate the same amount of electricity. Table 2.1 summaries the operating characteristics of various engine types. These technologies are discussed below.

2.1.1 - Steam Turbine Cogeneration

The steam turbine is most usually applied to cogeneration as a topping cycle, that is, as shown on Figure 2.1, a power generating cycle superimposed on a process steam demand. The electricity produced is a byproduct of a requirement for process heat. The steam turbine shown on Figure 2.1 has a single exhaust and is referred to as a back pressure turbine. Steam can also be extracted from intermediate points between the turbine inlet and outlet to serve varying process steam pressure requirements.

Different cogeneration options have different heat-power ratios, that is, the ratio of the number of heat units made available for useful purposes to the number of equivalent electricity units produced. In the case of a simple back-pressure steam turbine cogeneration cycle, this ratio is about 18:1. It can vary, depending on initial steam temperature and pressure and steam turbine internal efficiency. The ratio will decrease as the proportion of intermediate extraction increases.

TABLE 2.1

OPERATING CHARACTERISTICS BY ENGINE TYPE

Engine Type	Size Range MWe	Efficiency at Design Point*	Part Load Efficiency	Max. Temp. of Recoverable Ht.	Recoverable Heat 1000 x Btu/kWh**	Heat to Power Ratio
Steam Turbine						
Extraction-Condensing	30 - 300	0.25 - 0.30	Fair	200 - 600°F	11 - 35	3 - 10
Back Pressure	20 - 200	0.20 - 0.25	Fair	200 - 600°F	17 - 70	5 - 20
Combustion Gas Turbine	0.3 - 120	0.25 - 0.30	Poor	900 - 1200°F	3 - 11	2 - 3.5
Indirectly Fired Gas Turbines						
Open Cycle	10 - 85	0.25 - 0.30	Poor	700 - 900°F	3.5 - 8.5	1 - 2.5
Closed Cycle	5 - 350	0.25 - 0.30	Excellent	700 - 900°F	3.5 - 8.5	1 - 2.5
Diesel Engines	0.05 - 25	0.35 - 0.40	Fair	500 - 700°F	4 - 6	1.2 - 1.7

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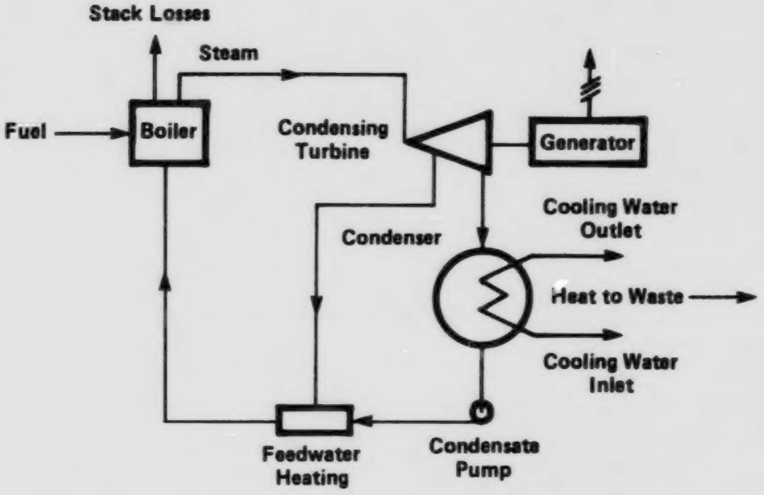
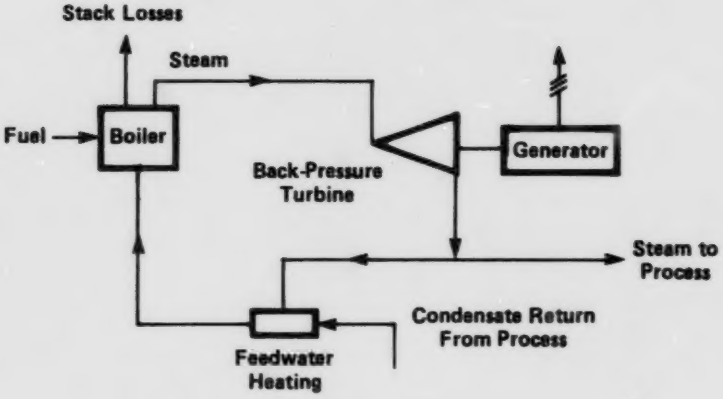
* Design for optimum running efficiency.

**This is the recoverable heat that can be used for process uses after the steam has left the turbine. It varies with the energy extracted by the turbine.


Stack Losses
Steam
Fuel
Boiler
Condensing Turbine
Generator
Cooling Water Outlet
Condenser
Heat to Waste
Cooling Water Inlet
Feedwater Heating
Condensate Pump

a) CONVENTIONAL POWER GENERATION


Stack Losses
Steam
Fuel
Boiler
Generator
Back-Pressure Turbine
Steam to Process
Condensate Return From Process
Feedwater Heating

b) COGENERATION

Figure 2.1

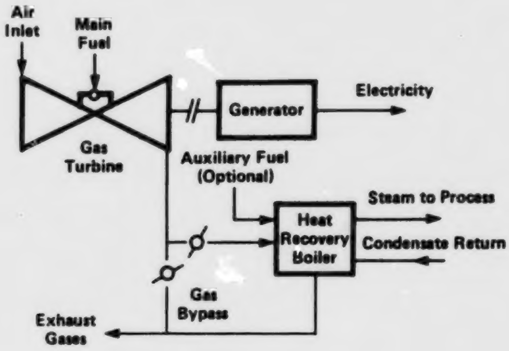
Steam supplied to the turbine is generated in a boiler which can be fueled with virtually any fuel available, be it coal, oil, natural gas, process off-gas, municipal refuse, wood wastes or other industrial wastes. Alternately, the steam can be generated in a heat recovery boiler supplied with high temperature gases from a process, such as copper smelting, or from a gas turbine. Initial steam pressures of up to 1800 psig (12.4 MPa) and temperatures of up to 1000°F (540°C) have been used for steam turbine cogeneration, however, 1250 psig (8.6 MPa) and 950°F (510°C) is a popular combination, avoiding the much more demanding operating and maintenance standards required at the higher conditions.

There is virtually no limit to the size of a steam turbine cogeneration unit in terms of industrial requirements. There are several plants in the US of several hundred megawatts. In Canada, probably one of the largest installations is the Great Lakes Paper mill at Thunder Bay, Ontario, totalling some 87 600 kW. In general, steam cogeneration plants are 20 000 kW or less.

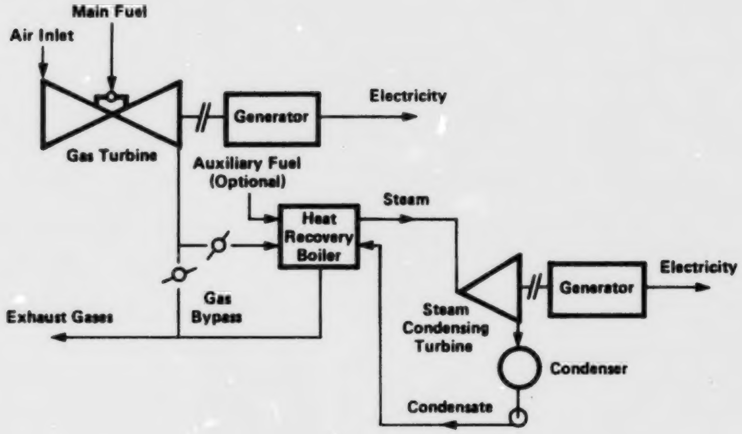
In some cogeneration plants, a condensing 'tail' is added to the back pressure turbine to provide a measure of control over purchased power peak demands. The turbine and generator must be sized for the additional power. The condenser allows a method of matching changes in load by varying the turbine back pressure.

2.1.2 - Gas Turbine Cogeneration

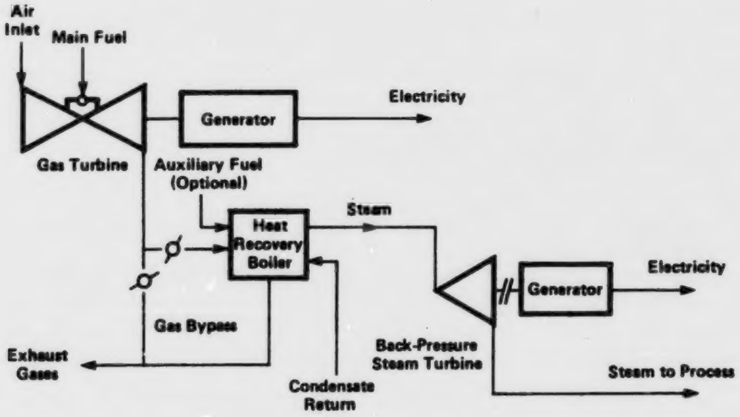
Gas turbines can be applied to cogeneration in a variety of ways, three of which are shown on Figure 2.2. The most common is that shown as (a). The gas turbine exhaust gases are fed to a heat recovery steam generator (HRSG) which produces steam for process at one or more pressure levels. The temperature of the exhaust gases is about 900°F


Air Inlet
Main Fuel
Gas Turbine
Generator
Electricity
Auxiliary Fuel (Optional)
Heat Recovery Boiler
Steam to Process
Condensate Return
Gas Bypass
Exhaust Gases

a) GAS TURBINE COGENERATION


Main Fuel
Air Inlet
Gas Turbine
Generator
Electricity
Auxiliary Fuel (Optional)
Heat Recovery Boiler
Steam
Generator
Electricity
Steam Condensing Turbine
Gas Bypass
Exhaust Gases
Condenser
Condensate

b) GAS TURBINE COMBINED CYCLE


Air Inlet
Main Fuel
Gas Turbine
Generator
Electricity
Auxiliary Fuel (Optional)
Heat Recovery Boiler
Steam
Generator
Electricity
Gas Bypass
Back-Pressure Steam Turbine
Exhaust Gases
Condensate Return
Steam to Process

c) GAS TURBINE COMBINED COGENERATION

Figure 2.2

(480°C) permitting the generation of superheated steam with pressures up to 1250 psig (8.6 MPa).

The second method, (b), combines a gas turbine cycle with a steam turbine cycle and is referred to as a combined cycle. It is not truly cogeneration since only electrical power is produced; there is no simultaneous production of process steam. The combined cycle has a high efficiency (41% or 8300 Btu/kW.h) relative to conventional control steam plants and is used by power utilities to meet upper range and peak loads.

Option (c), which can be referred to as combined cogeneration, consists of a gas turbine exhausting to a heat recovery steam generator (HRSG) which in turn supplies steam to a back pressure steam turbine, the exhausted steam going to process. A notable example is the Syncrude power plant at the tar sands refinery at Mildred Lake in Alberta.

The heat-power ratio for the simple gas turbine cogeneration cycle, option (a), is typically in the range 2:1 to 3:1 compared with 18:1 for the back-pressure steam-turbine option. The ratio is less for a combined cogeneration plant, (c), in the order of 1.5:1, depending on the initial steam conditions and the process steam conditions.

The heat-power ratio can be lowered by firing fuel in the gas turbine exhaust gas stream before it enters the HRSG. Alternatively, the exhaust gases could be fed to a conventional boiler via the combustion air system, the sensible heat in the gases displacing some of the fuel normally fired. The overall efficiency or heat rate of electricity generation would remain the same, 4000 to 4200 Btu/kW.h (4220 to 4430 kJ/kW.h).

A gas turbine cogeneration plant is restricted to the use of hydrocarbon fuels. Solid fuels such as coal or wastes cannot be used. Considerable work is being carried out on the development of solid fuel gasification to produce a gas turbine fuel, but it is still very much in the developmental stage.

Gas turbine generating units are available with capacities of over 100 MW. The largest gas turbine cogeneration plant in Canada is that at Dow Chemical in Sarnia, Ontario where three 50-MW units produce steam at 1250 psig (8.6 MPa) for use in steam turbines and process. Smaller aircraft gas turbines are available (250 kW) but these tend to be significantly more expensive than other cogeneration methods in the same power range.

In general, a gas turbine cogeneration plant has a lower first cost than a steam turbine plant of comparable capacity and requires less room. Where natural gas is available at a sufficiently low price, the gas turbine option is becoming the favored course of action.

2.1.3 - Diesel Engine Cogeneration

The diesel engine cogeneration option is shown on Figure 2.3. The exhaust gas temperature is in the range 500 to 700°F (260 to 371°C). A steam or hot-water waste-heat boiler located in the engine exhaust can produce saturated steam at pressures of up to 150 psig (1033 kPa) or hot water with temperatures of up to 250°F (138°C). In addition, low grade heat can be recovered from the engine cooling jacket and used to preheat the recovery boiler feedwater, preheat the fuel if necessary or to provide space heating.

Diesel engines range in capacity from a few kilowatts to as much as 36 000 kW. Very small, high-speed diesel engines, fueled by distillate oil or natural gas, are components of some of the packaged cogeneration units offered for residential and commercial use. Medium-speed units, 500 rpm, range from a few hundred kilowatts to about 20 MW and are the most commonly associated with cogeneration at the present time. Slow-speed units, 125 to 150 rpm, with capacities ranging from

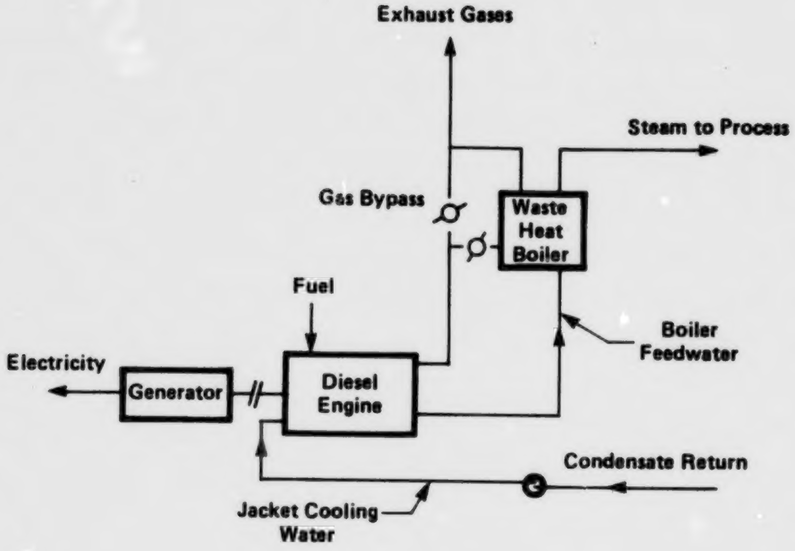

Exhaust Gases
Steam to Process
Gas Bypass
Waste Heat Boiler
Fuel
Boiler Feedwater
Electricity
Generator
Diesel Engine
Condensate Return
Jacket Cooling Water

Figure 2.3

DIESEL ENGINE COGENERATION

10 to 36 MW are associated with, as yet, a few industrial cogeneration plants. A notable example is the 23-MW slow-speed installation at the Hoffman-LaRoche pharmaceutical plant in New Jersey. The waste heat recovery system generates hourly 160 000 lb of steam and 26 000 gal of hot water.

The heat-power ratio of a diesel engine cogeneration plant is approximately 1.5:1, considerably lower than the steam-turbine option and lower than the gas-turbine option. In the diesel case, the generation of process heat is a byproduct of a requirement for electricity; it is a bottoming cycle.

The diesel engine is the central component of packaged cogeneration units being actively marketed in the US. These packages or modules consist essentially of four sub-modules - energy generator, heat transfer, electric interface and control. A typical specification for a 60 kW module includes 440 000 Btu/h (420 kJ/h) of hot water; efficiency of 26.4% electrical and 83.1% combined electrical and thermal output.

2.1.4 - Organic Rankine Cycle

Rankine turbine cycles are usually associated with high pressure and high temperature steam. The cycle heat transport fluid need not necessarily be steam/water. An organic fluid, such as freon, ammonia, Dowtherm A, methanol, benzene and methylchloride, all having much lower vapor pressures and boiling points than water, can be used in a Rankine turbine cycle. Hence the organic Rankine cycle can operate at much lower temperatures and receive its driving heat from low temperature sources such as diesel engine exhausts and jacket cooling water or process waste streams.

The arrangement of an organic Rankine cycle (ORC) is shown on Figure 2.4. In the Rankine system, a liquid working fluid is heated and vaporized in a vapor generator (boiler) at constant pressure. The

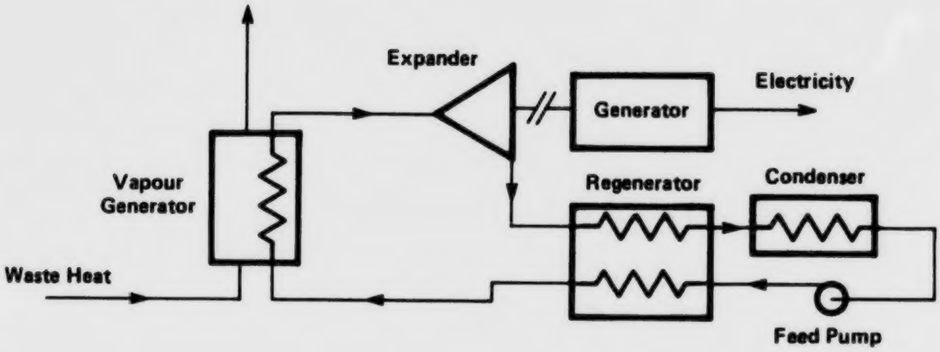

Expander
Generator
Electricity
Vapour Generator
Regenerator
Condenser
Waste Heat
Feed Pump

Figure 2.4

ORGANIC FLUID RANKINE BOTTOMING CYCLE

hot vapor is expanded to a lower pressure in an expander (turbine), producing electric or shaft power. The expander exhaust is then cooled and condensed at constant pressure. The condensed fluid is pressurized, preheated in a regenerator and returned to the vapor generator.

The large majority of ORCs currently in commercial use employ steam as the working fluid. These systems have thermal efficiency ranging from 14 to 36%, operate in the temperature range of 400° to 1000°F (205° to 540°C) and have capacities of 500 kW or more.

New ORC systems using organic fluids are available in capacities ranging from 2000 to 3000 kW. These systems can operate at low temperatures, 200° to 340°F (95° to 70°C) but have efficiencies less than 13%. Research is being carried out using organic fluids which will permit operation at 1000°F (540°C) with efficiencies up to 20%.

A feature unique to the ORC is a need for a supply of condenser cooling water or, if practicable, an air-cooled condenser. The investment required for an ORC is high when compared with conventional power generation, $1,200 to $1,800 per installed kilowatt.

A basic problem with bottoming cycles is that the ratio of mechanical power produced to heat recovered goes down as the temperature falls. Although the heat may be free, the low recovery means that larger and more expensive equipment is needed to generate a given amount of mechanical power as the temperature of the heat source decreases.

2.1.5 - Fuel Cells

Fuel cells directly transform the chemical energy of a fuel and an oxidant into electrical energy without combusting the fuel. A fuel, such as hydrogen, is introduced at the negative electrode, or anode, which contains a catalyst, usually platinum. The hydrogen passes through a liquid or solid electrolyte where it dissociates into electrons and ions. At the positive electrode, the cathode, oxygen is introduced and similarly dissociates. Connecting the two electrodes in an external circuit enables the flow of hydrogen electrons which is a direct current of electricity. If necessary, the dc power can be converted to ac. The hydrogen ions combine with the oxygen electrons in the cathode to form water.

The fuel cell can be based on one of five types of electrolyte: phosphoric acid, carbonate, solid oxide, alkaline and solid polymer. The first three are under active consideration for commercial power production. Of these, only the phosphoric-acid unit is likely to be commercial within the next 10 years. Natural gas, reformed to give a hydrogen-rich gas, is the currently preferred fuel and air is the oxidant. The major impetus to fuel cell development is the high electrical conversion efficiencies that can be achieved; 45% when generating electricity alone and 85% when being used for cogeneration.

Although the fuel cell is still in the development stage, it has potential as a small-scale cogenerator that could be the best choice for commercial and residential applications. The capacity of the fuel cell which is presently being tested by the US Department of Energy at several sites is 40 kW. Other research programs concern fuel cells with capacities of up to 11 MW. An advantage of fuel cells for urban or farm use is the low-level emission of atmospheric pollutants compared with other forms of fueled cogeneration.

2.2 - Choice of Technology

A wide variety of issues must be addressed in the selection of appropriate cogeneration technology. These issues fall into two major categories; those associated with the characteristics of available equipment and those associated with the potential market.

2.2.1 - Equipment Characteristics

A significant technical limitation is the availability of appropriately sized cogeneration equipment. Much of the equipment is adopted from other industries and processes, thus, their preferred sizing dictates the equipment sizes, available for cogeneration.

This is particularly true for small gas turbines. Aircraft turboprop engines dominate in the 250 kW to 900 kW size range while the larger aircraft turbojets range from 3 MW to 15 MW are designed specifically for industrial applications. While intermediate sizes are technically feasible, the predicted volume of cogeneration market does not warrant the development costs of new turbines sizes.

The same is true for diesel generators, most of which are diverted from automotive, construction equipment and marine applications.

The situation for steam turbines is somewhat better. The smaller steam turbines are normally solid wheel impulse back pressure units which are sized to suit more commonly used pump sizes for the power and process industries. They are very easily adapted as electrical generator drives and are easier to retrofit to existing installations than gas turbines or diesels, further enhancing their acceptance.

Direct drives for refrigeration compressors are now being evaluated for use in supermarkets, and in meat and dairy product firms in the United States, particularly in areas where gas prices offer an advantage over electrical power rates. One Los Angeles store is now testing a 30 kW diesel prepackaged refrigeration cogeneration unit. The initial cost is 1.6 times the cost for an electrically driven unit but is expected to pay for itself in 3.4 years in avoided energy costs. The unit also includes an inline generator allowing the production of up to 25 kW in off peak refrigeration hours. The waste heat is used in an absorption chiller and in space heating. These units warrant further investigation in a Canadian context.

2.2.2 - Market Characteristics

Each cogeneration application is unique. Food processing, for instance, experiences high energy demand coincident with crop harvesting. Unionized plants trade off increased capacity with shift time premiums resulting in daytime operation rather that continuous process.

The method of financing, particularly for office building or shopping mall construction, also has an impact on the choice of cogeneration system. Office towers can be built with a large centralized heating ventilating and air conditioning (HVAC) systems or they can be developed with the intent of selling entire floors leaving the HVAC choice to the individual floor owners. This results in a separate HVAC facility for each floor.

Shopping mall construction financing is usually initiated by the sale of one major store to a national retail chain. While this main store will use a centralized HVAC system, the remaining, smaller stores are sold or leased on the basis that the new owner (lessor) will install his own packaged HVAC units. Since these smaller stores often change owners during the life of the mall, the owners are reluctant to install anything that is not conventional technology or to invest in equipment for the benefit of his successor. Where large centralized HVAC systems are easier to convert to cogeneration, the smaller 'packaged unit' stores often lack the necessary space or access to retrofit with cogeneration units.

Plant size can govern the selection of the cogeneration system. More significant is the requirement for a particular electricity-to-heat demand ratio, the capability and experience of the operating personnel plus the availability of physical space and access. Generally, for a plant size of under 3 MW, the diesel generator has the lowest cost and quickest payback. In addition, diesel technology is fairly well known and as such has better acceptance. Diesel generators are compact and more easily accommodated. The 3 MW size will normally cover the power requirements of a shopping mall or an office tower.

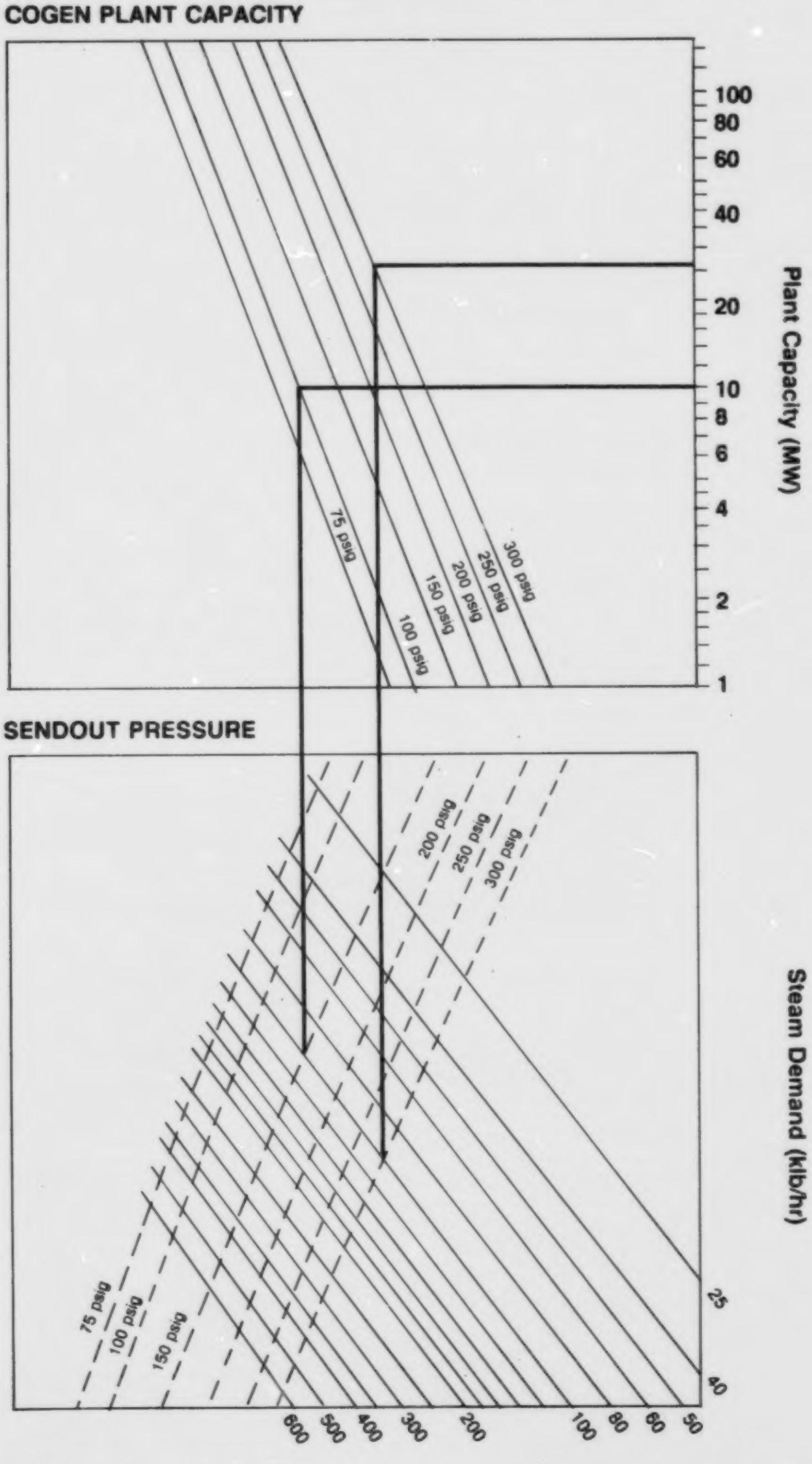
Between 3 MW and 15 MW the gas turbine is the better selection, however, in this size range, it is advantageous to use a combined cogeneration system with the accompanying waste heat steam generator and steam turbine. While this lowers the heat rate by 2000 Btu/kWh it also increases the size of the installation considerably. This also increases the installation cost (possibly requiring a new building) as well as the peripheral equipment required, particularly electrical equipment. Between 15 MW and 120 MW the steam turbine and gas turbine are roughly equivalent and the selection is dependent more on the power to heat requirement.

The use of steam capacity to segment industries into small, medium and large unfortunately does not consider the pressure of the steam. As Figure 2.5 illustrates for gas turbine technology, a 10 MW is sufficient to produce, however, to produce the 100 000 pph of steam at 150 psig the same volume of steam at 300 psig would require a 26 MW plant.

2.2.3 - Equipment Cost Projections

Figure 2.6 displays the variations in unit capital costs for the two principal components of a cogeneration plant. These figures are developed from a review of the literature and discussions with equipment manufacturers. The upper graph plots the unit costs of turbine-generator sets as a function of power output. Gas and back-pressure steam turbine costs are presented. The capital costs for high and low pressure steam boilers as well as waste heat recovery boilers are plotted in the lower graph as a function of steam output.

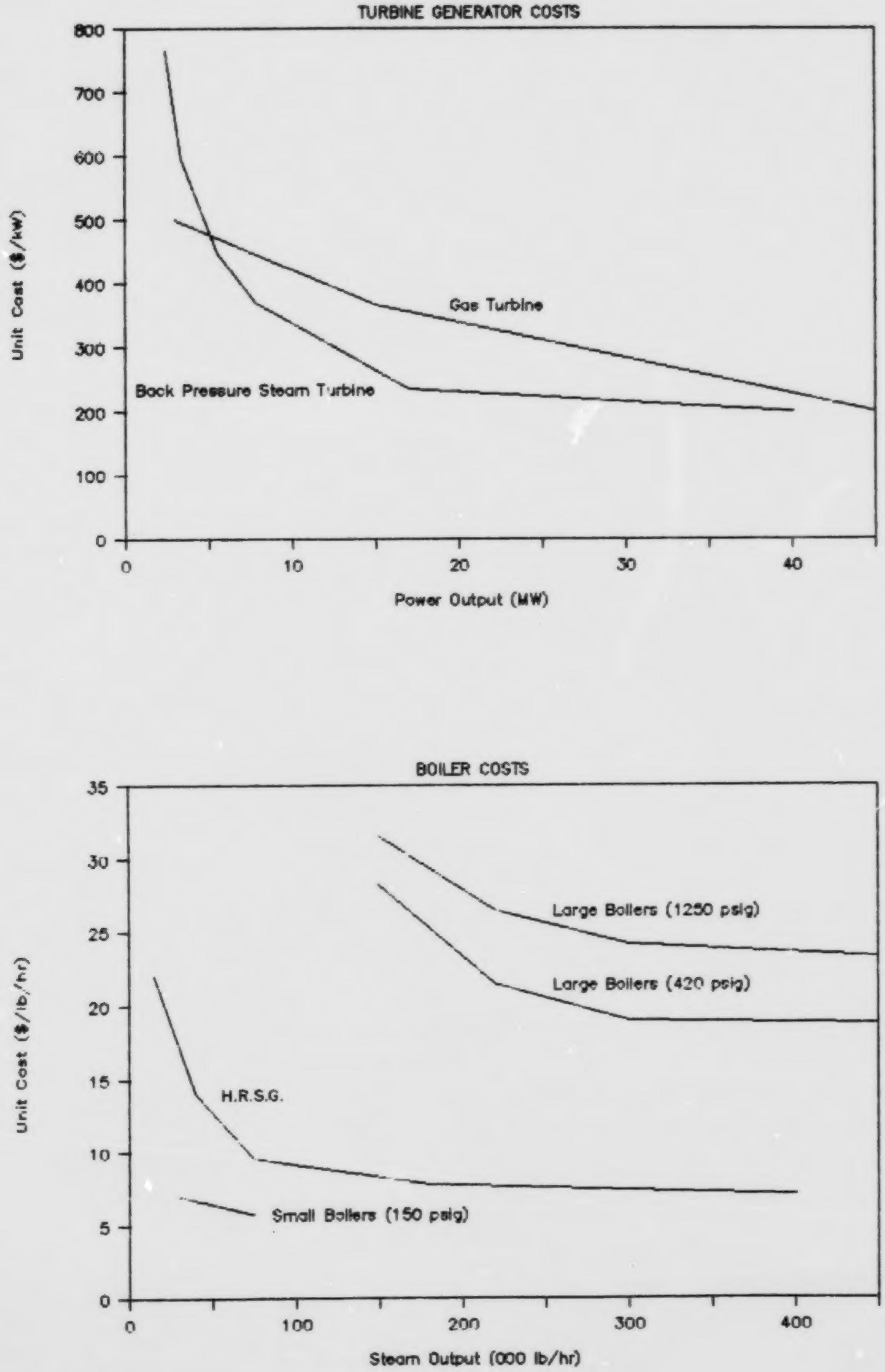
Figure 2.5
STEAM DEMAND CHARACTERISTICS
versus COGENERATION PLANT CAPACITY



Source: Gas Turbine World

Figure 2.6

EQUIPMENT COSTS



Diesel Generator

Prices which now range $780/kW for smaller units to $450/kW for larger units will become slightly lower in the future more due to volume of sales than technological advancement. Diesel is a fairly mature technology which leaves only improvements in generators and switch gear to lower the unit cost.

Gas Turbines and Steam Turbines

Gas and steam turbine prices range from $500/kW to $200/kW as unit size increases. International competition for markets for these engineered products is strong and tends to keep constant dollar prices relatively stagnant.

A conservative estimate of turbomachinery prices is that they will increase in line with the consumer price index. Research directed at ceramic engine components could, if successful, reduce the cost of small gas turbines significantly.

Steam Generators

Similarly, the large number of international steam generator manufacturers, coupled with low international demand, has kept prices at or below levels of annual inflation. This will remain the case for the remainder of the 1980s and the early 1990s. The manufacture of steam generators is a very mature technology. The only areas of possible technological advancement appear to be in the computer/robotic fabrication of the steam generator.

2.2.4 - Data Limitations

Published data on existing installations in some industry sectors is not readily available. Numerous examples can be found for diesel generator and steam turbine applications and, to a lesser degree, large combined cycle cogeneration installations. Areas that warrant further investigation are institutional and commercial building cogeneration, as well as small gas turbine cogeneration applications.

2.3 - Estimates of Technical Potential

The technical potential for cogeneration in Ontario was estimated within the framework discussed in Chapter 1 and based on the preceeding considerations (Section 2.2). For each of the four economic sectors (industrial, institutional, commercial and residential) and heat demand category (low, medium and high), an appropriate cogeneration technology was selected based on equipment availability, flexibility of fuel choice, heat-to-power ratios and operating considerations. Given the selected technologies and estimated total heat demands by end-use sector, the total technical potential for electric power was computed for each cell as presented in Table 2.2. The total potential for all sectors and heat demand categories is 9962 MW.

In the industrial sector, the technical potential of 3774 MW is within the range estimated in earlier studies (see Chapter 1) and compares with the average figure of 3200 MW estimated in these reports. The sectoral potential is dominated by the high heat demand category which accounts for 76% of the total. With the exception of the Pulp and Paper subsector, the selected technology in the industrial sector is gas turbines. In the pulp and paper industry, steam turbine cogeneration plants were selected because they may use wood wastes as fuel.

TABLE 2.2

FRAMEWORK FOR THE ESTIMATION OF TECHNICAL POTENTIAL

	Heat Demand Category								
	Low			Medium			High		
	(< 25,000 #/hr)			(25,000 to 100,000 #/hr)			(> 100,000 #/hr)		
Sector & Subsector	Cogen System	Total Steam Demand (000#/hr)	Assoc Power (MW)	Cogen System	Total Steam Demand (000#/hr)	Assoc Power (MW)	Cogen System	Total Steam Demand (000#/hr)	Assoc Power (MW)
Industrial									
Pulp & Paper	STW	914	16	STW	1,838	32	STW	16,966	385
Iron & Steel	GT	118	6	GT	338	18	GT	8,216	426
Smelting & Ref	GT	242	13	GT	788	41	GT	3,000	156
Petroleum Prod	GT	77	4	GT	113	6	GT	11,093	575
Chemicals	GT	637	33	GT	1,838	95	GT	8,277	429
Other Mfg	GT	4,921	255	GT	7,763	403	GT	17,000	882
Total		6,908	327		12,675	594		64,551	2,853
Institutional									
Universities	N/A	-	-	ST	540	59	STD	1,014	87
Hospitals	D	795	141	D	1,248	215	N/A	-	-
Total		795	141		1,788	273		1,014	87
Commercial									
Shopping Malls	D	4,050	342	GT	3,635	307	N/A	-	-
Offices	D	10,321	682	D	6,886	455	N/A	-	-
Total		14,371	1,024		10,521	762			
Residential									
Apartments	D	52,029	3,902	N/A	-	-	N/A	-	-
TOTAL		74,103	5,394		24,984	1,629		65,565	2,940

TOTAL TECHNICAL POTENTIAL: 9,962 MW

ST - Steam Turbine
STD - Steam Turbine with Supplemental Diesel
STW - Steam Turbine (with wood waste)
GT - Gas Turbine
D - Diesel
N/A - No technical potential indicated.

TABLE 2.2 (Cont'd)

INDUSTRIAL CAPACITY

Industrial Sector	Heat Demand Category (#/hr) Up to 25000	Heat Demand Category (#/hr) 25000-100000	Heat Demand Category (#/hr) Above 100000	Total Capacity
Aggregated Capacity (#/hr)				
Chemicals	636500	1837500	8277000	10751000
Rubber & Plastics	241500	1125000	1250000	2616500
Meat	165000	187500	800000	1152500
Fruit & Veg	605500	787500	1750000	3143000
Grain & Sugar	384000	937500	1650000	2971500
Alcoholic Bev	70500	262500	2150000	2483000
Other Food & Bev	937000	1200000	150000	2287000
Textiles	735500	900000	1400000	3035500
Iron & Steel	118000	337500	8215500	8671000
Mining	241500	787500	3000000	4029000
Petroleum Prod	77000	112500	11092500	11282000
Forest Products	914000	1837500	16965500	19717000
Machinery & Equip	272000	937500	6800000	8009500
Fabricated Metal	441500	487500	450000	1379000
Non-Metallic Min	395000	375000	300000	1070000
Other Mfg	673000	562500	300000	1535500
TOTAL	6907500	12675000	64550500	84133000
Capacity Summary (#/hr)				
Pulp & Paper	914000	1837500	16965500	19717000
Iron & Steel	118000	337500	8215500	8671000
Smelting & Ref	241500	787500	3000000	4029000
Petroleum Prod	77000	112500	11092500	11282000
Chemicals	636500	1837500	8277000	10751000
Other Mfg	4920500	7762500	17000000	29683000
TOTAL	6907500	12675000	64550500	84133000

Source: Acres International Ltd., Ontario Industrial Boiler Survey, 1983.

TABLE 2.2 (Cont'd)

INSTITUTIONAL DEMAND

Universities

Distribution

Steam Demand Range (#/hr)	Average Sample Size	Number In Sample (units)	------ Survey Parameters ------			Heat Demand Category	Number In Universe (units)	Universe Steam Demand (000#/hr)	Universe Electrical Demand (MW)	Universe Annual Energy (GWh)
			Steam Demand (000#/hr)	Electrical Demand (MW)	Annual Energy (GWh)					
< 150,000	89000	4	60.0	6.5	37.0	Medium*	9	540.0	58.5	333.0
> 150,000	173000	5	169.0	14.5	77.0	High*	6	1014.0	87.0	462.0

Hospitals

Distribution

Number of Beds	Average Sample Size	Number In Sample (units)	------ Survey Parameters ------			Heat Demand Category	Number In Universe (units)	Universe Steam Demand (000#/hr)	Universe Electrical Demand (MW)	Universe Annual Energy (GWh)
			Steam Demand (000#/hr)	Electrical Demand (MW)	Annual Energy (GWh)					
100 to 199	150	31	6.9	1.2	6.1	Low	31	213.9	37.2	189.1
200 to 399	290	37	15.7	2.8	12.3	Low	37	580.9	103.6	455.1
> 400	590	39	32.0	5.5	24.5	Medium*	39	1248.0	214.5	955.5

* - Based on Case Study

TABLE 2.2 (Cont'd)

COMMERCIAL DEMAND

Shopping Malls

Inventory

Floor Area Range (000 m2)	Number of Centres	Number of Stores	Total Floor Space (000 ft2)
< 1.1	190	1318	1512.3
1.2 - 2.3	163	1543	2890.1
2.4 - 4.6	131	1698	4696.3
4.7 - 9.2	90	1760	6087.0
9.3 -23.0	55	1607	9248.3
23.1 -46.0	28	1895	9642.3
46.1 <	14	1997	12360.2
Total	671	11818	46436.5

Source: Retailing in Regional Municipalities,
Metropolitan Toronto Planning Department, 1983

Unit Energy Consumption

Heating/Cooling Peak	68.7 Btu/ft2/hr	
Peak Power	5.8 Watt/ft2	
Energy	23.4 kWh/ft2/yr	
Food Store	38.7 kWh/ft2/yr	20%
Non-Food Store	19.6 kWh/ft2/yr	80%

Population Covered by Inventory	3723197
Inventory Area per Capita (ft2)	12.47
Total Provincial Population	8975000
Inventory to Universe Factor	2.41

Distribution

Floor Space (000 m2)	Average Size in Inventory (000 ft2)	Average Number in Inventory	---- Case Study Parameters ---- Steam Demand (000#/hr)	Electrical Demand (MW)	Annual Energy (GWh)	Heat Demand Category	Number in Universe (units)	Universe Steam Demand (000#/hr)	Universe Electrical Demand (MW)	Universe Annual Energy (GWh)
< 4.6	18.8	484	1.3	0.1	0.4	Low	1167	1507.2	127.2	514.1
4.6 to 23	105.8	145	7.3	0.6	2.5	Low	350	2543.0	214.7	867.4
> 23.0	523.9	42	36.0	3.0	12.3	Medium*	101	3635.0	306.9	1239.8

* - Based on Case Study

TABLE 2.2 (Cont'd)

COMMERCIAL DEMAND (Cont'd)

Offices

Inventory

Floor Area Range (000 ft2)	Number of Bldgs	Total Floor Space (000 ft2)
20 - 100	536	25771.2
100 - 250	189	29311.6
250 - 500	55	17777.8
500 - 750	15	9037.4
750 - 1000	5	4364.6
1000 - 1250	2	2233.0
1250 - 1500	1	1270.4
1500 - 1750	0	0.0
1750 - 2000	1	2049.0
Total	804	91815.0

Source: Royal LePage, Commercial Real
Estate Services, 1986

Unit Energy Consumption

Heating/Cooling Peak	96.8 Btu/ft2/hr
Peak Power	6.4 Watt/ft2
Energy	20.4 kWh/ft2/yr

Population Covered by Inventory	3121687
Inventory Area per Capita (ft2)	29.41
Total 1985 CMA Population	6042096
Inventory to Universe Factor	1.94

Distribution

Floor Space (000 ft2)	Average Size in Inventory (000 ft2)	Average Number in Inventory	---- Case Study Parameters ---- Steam Demand (000#/hr)	Electrical Demand (MW)	Annual Energy (GWh)	Heat Demand Category	Number in Universe (units)	Universe Steam Demand (000#/hr)	Universe Electrical Demand (MW)	Universe Annual Energy (GWh)
< 100	48.1	536	4.7	0.3	1.0	Low	1037	4826.4	319.1	1017.1
100 to 250	155.1	189	15.0	1.0	3.2	Low	366	5494.6	363.3	1157.9
> 250	465.0	79	45.0	3.0	9.5	Medium*	153	6886.3	455.3	1451.2

* - Based on Case Study

TABLE 2.2 (Cont'd)

RESIDENTIAL DEMAND

Apartments

Inventory

Units in Bldg (units)	Total Number of Units
< 6	274915
6 - 19	57288
20 - 49	75344
50 - 199	242387
> 200	162741
Total	812675

Source: Commission of Inquiry into Residential Tenancies,
Research Study No. 30, 1986

Unit Energy Consumption

Heating/Cooling Peak	80000.0 Btu/Unit/hr
Peak Power	6000.0 Watt/Unit
Energy	30000.0 kWh/Unit/yr

Rental Stock Covered by Inventory	812675
Total Provincial Rental Stock	1100000
Inventory to Universe Factor	1.35

Distribution

Number of Units	Average Size in Inventory (units)	Average Number in Inventory (Bldgs)	---- Case Study Parameters ---- Steam Demand (000#/hr)	Electrical Demand (MW)	Annual Energy (GWh)	Heat Demand Category	Number in Universe (Bldgs)	Universe Steam Demand (000#/hr)	Universe Electrical Demand (MW)	Universe Annual Energy (GWh)
20 - 49	35.0	2153	2.8	0.2	1.1	Low	2914	8159.2	611.9	3059.7
50 - 199	125.0	1939	10.0	0.8	3.8	Low	2625	26250.0	1968.8	9843.8
> 200	250.0	651	20.0	1.5	7.5	Low*	881	17620.0	1321.5	6607.5

* - Based on Case Study

In the institutional sector, the technical potential is estimated to be approximately 500 MW or about 5% of the total provincial potential. Medium heat demands in hospitals account for 43% of the sectoral potential. Diesel cogeneration is the suggested technology for hospitals and steam turbines for universities.

In the commercial sector, the technical potential is 1786 MW, or 18% of the total. Office buildings account for 66% of the commercial potential. The low-heat-demand shopping malls, and low- and medium-heat-demand office buildings, are shown to use diesels. In the larger (medium heat demand) malls, gas turbines are the preferred technology. Finally, in the residential sector, multi-unit apartment buildings, which appear in the low heat demand category only, are estimated to provide some 3900 MW of technical potential. This is nearly 40% of the total Provincial potential of 9962 MW.

The importance of considering various categories of heat demand is underlined by the findings that over half of the total Provincial potential occurs in the low heat demand category. The large potential in industry's high heat demand category is balanced by the significant technical potential in the low and medium categories of the institutional, commercial and residential sectors.

2.4 - Case Study Data

A number of case studies were assembled to develop a cogeneration database for the estimation of technical as well as economic and financial potential. The parameters determined through the case studies were applied over the entire end-use sector in the calculation of the total technical potential (Table 2.2). This is a theoretical potential based on few technical and no economic constraints. In the residential sector, for example, the total technical potential includes that associated with all multi-units apartments in excess of 20 units.

Technical and operational realities would, in general, preclude cogeneration in all but the largest buildings. Thus, the database has been modified and only the case study data for residential buildings with more than 200 units has been carried forward to the analysis of economic and financial potential.

The case study data summarized below is presented in detail in Appendix B.

Industrial Sector

Case studies were developed for the low and medium categories of heat demand and a previous Ontario data base of 56 large steam users (high heat demand) was updated using current capital cost estimates.* Discussions with suppliers indicate equipment costs have declined in real terms in recent years such that the nominal 1986 costs are about the same as they were in 1978-79. A preliminary economic screening of gas turbine and steam turbine technology was conducted in all three heat demand categories. The screening was based on separate case studies for the low and medium heat demand categories and adjustments to the high heat demand data base reflective of the cost and operational impacts of a change from steam turbine to gas turbine equipment. The technology associated with the lowest supply price was selected. The determination of supply price is discussed in Section 3.1.1. In all cases, the installed cost of cogeneration was based on incremental equipment costs relative to a new conventional steam plant.

The low and medium heat demand case studies are based on steam turbine and gas turbine technology respectively except in the pulp and paper industries where wood-fueled steam turbine plants were used. In the high heat demand category, natural gas-fired gas turbine plants were selected in all but the pulp and paper cases which involve wood waste as the incremental fuel.

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* The data base of large steam users is adapted from Acres Shawinigan (1979).

Institutional Sector

Two case studies were developed for the university sector (medium and high heat demand categories) and one for the hospital sector (medium heat demand). Although a technical potential was indicated in Table 2.2 for the small hospital category, no case study is shown since installations in this market are not expected to show economic feasibility.

Commercial Sector

Technical potential was indicated in the low and medium heat demand categories for large shopping malls and offices. Case studies were developed for the medium category only since projects in the low category were not expected to be economically viable.

Residential Sector

Technical potential was indicated for apartment buildings containing over 200 units. This corresponds to the low heat demand category in Table 2.2.

3 - ECONOMIC POTENTIAL

3 - ECONOMIC POTENTIAL

3.1 - Approach and Assumptions

3.1.1 - Supply Prices

To establish economic feasibility, it must be demonstrated that a cogeneration application can produce energy at a price competitive with that of alternative sources of supply. This supply price is used as an indicator of economic feasibility.* The economic analysis adopts a public (or social) perspective using a social discount rate and compares the supply price of electricity from cogeneration with that of conventional electricity supply.

Supply prices measure costs as opposed to prices per unit of energy output. This allows a consistent comparison of cogeneration applications whose characteristics may vary according to scale of investment, time profile of development, useful operating life and type of energy produced or conserved. Capital and operating costs exclude transfer payments such as taxes, capital grants and other incentives and thus indicate only physical "brick and mortar" costs. The supply price defines the constant real (1985) dollar price of energy required to meet project costs at a given real discount rate. Note that the study measures all costs in real 1985 dollars. Put another way, the present worth (PW) of a project's capital and operating costs will be equal to the PW of the product of its supply price and quantity of energy supplied by the project. The supply price is computed by dividing the PW of costs by the PW of energy supplied where the present worth of each is calculated using a real social discount rate appropriate to the investment. The supply price may also be thought of as the levelized (present value) production cost per kilowatt hour (kW.h) of electricity, measured in real (inflation adjusted) dollars and using a corresponding real discount rate. (Figure 3.1 provides an overview of the model used for economic analysis.)

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* Supply price may also be referred to as 'resource cost' or 'levelized production cost' or shadow price.

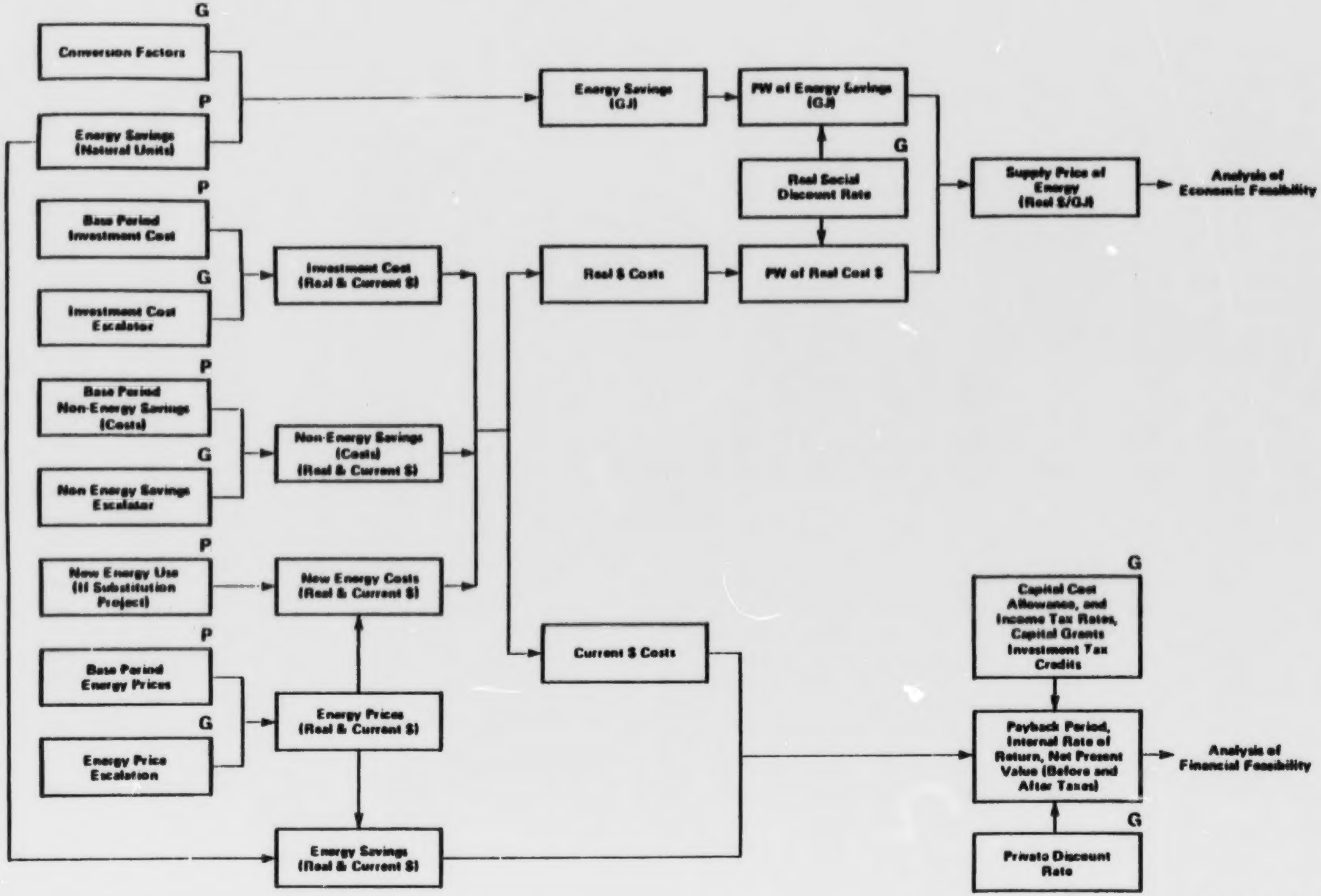
3.1.2 - Energy Prices

The economic feasibility of each application is assessed on the basis of comparative supply prices. The sector and fuel-specific supply price of electrical energy associated with a particular application is compared with the corresponding supply price of conventionally produced electrical energy. The supply prices of oil products, natural gas and wood fuels are used to measure the costs of incremental fuel requirements - these are assumed to equal market prices in the study period.

The market prices of oil products and natural gas are those used by the Ministry of Energy in their Energy 2000 publications. Table 3.1 details the forecasts of real and nominal fuel price over the study planning horizon. Real price escalation from 1985 to 2012 averages 2.5% per year. On the basis of previous studies, the price of wood waste is set at one third of the natural gas price. Sensitivity cases corresponding to higher and lower energy prices are examined in Chapter 7.

3.1.3 - Planning Horizon

The supply price analysis is carried out over a period of time equal to the estimated economic life of the project. For cogeneration applications, this economic life is 25 years. The selected base period for the analysis is 1985 and the construction or installation period for all projects is a single year (1987). The 25-year economic life of the project runs from 1988 to 2012 inclusive.


G
Conversion Factors
P
Energy Savings (Natural Units)
P
Base Period Investment Cost
G
Investment Cost Escalator
P
Base Period Non-Energy Savings (Costs)
G
Non Energy Savings Escalator
P
New Energy Use (If Substitution Project)
P
Base Period Energy Prices
G
Energy Price Escalation
Investment Cost (Real & Current $)
Non-Energy Savings (Costs) (Real & Current $)
New Energy Costs (Real & Current $)
Energy Prices (Real & Current $)
Energy Savings (Real & Current $)
Energy Savings (GJ)
Real $ Costs
Current $ Costs
PW of Energy Savings (GJ)
G
Real Social Discount Rate
PW of Real Cost $
Supply Price of Energy (Real $/GJ)
Analysis of Economic Feasibility
G
Capital Cost Allowance, and Income Tax Rates, Capital Grants Investment Tax Credits
Payback Period, Internal Rate of Return, Net Present Value (Before and After Taxes)
G
Private Discount Rate
Analysis of Financial Feasibility

Note: Project-specific and global input variables are denoted by P and G, respectively. All other boxes contain calculated variables.

Figure 3.1

LOGIC DIAGRAM OF THE ANALYTIC MODELS

TABLE 3.1

NOMINAL AND REAL FUEL
PRICE CALCULATIONS - Base Case Prices

	Nominal Fuel Prices ($/GJ)						- Escalation -		Real Fuel Prices ($/GJ)					
Year	Natural Gas		Wood	Electricity			Annual	Annual	Natural Gas		Wood	Electricity		
	Ind	Comm	Waste	Ind	Comm	Buy Back	CPI	Factor	Ind	Comm	Waste	Ind	Comm	Buy Back
1985	4.25	4.65	1.42	8.75	9.63	9.17	4.5%	1.000	4.25	4.65	1.42	8.75	9.63	9.17
1986	4.30	4.70	1.43	9.06	9.97	9.58	4.3%	1.043	4.12	4.51	1.37	8.69	9.56	9.19
1987	4.10	4.55	1.37	9.62	10.58	10.13	5.7%	1.102	3.72	4.13	1.24	8.73	9.60	9.19
1988	4.20	4.70	1.40	10.18	11.20	10.74	6.0%	1.169	3.59	4.02	1.20	8.71	9.58	9.19
1989	4.30	4.80	1.43	10.82	11.90	11.40	6.2%	1.241	3.46	3.87	1.15	8.72	9.59	9.19
1990	4.40	4.95	1.47	11.37	12.51	12.13	6.4%	1.320	3.33	3.75	1.11	8.61	9.47	9.19
1991	4.81	5.40	1.60	12.07	13.28	12.91	6.4%	1.405	3.42	3.84	1.14	8.59	9.45	9.19
1992	5.22	5.85	1.74	12.78	14.06	13.74	6.4%	1.495	3.49	3.91	1.16	8.55	9.40	9.19
1993	5.63	6.30	1.88	13.48	14.83	14.61	6.4%	1.591	3.54	3.96	1.18	8.48	9.32	9.19
1994	6.04	6.75	2.01	14.19	15.60	15.55	6.4%	1.692	3.57	3.99	1.19	8.38	9.22	9.19
1995	6.45	7.20	2.15	14.89	16.38	16.58	6.6%	1.804	3.58	3.99	1.19	8.25	9.08	9.19
1996	7.01	7.81	2.34	15.71	17.28	17.67	6.6%	1.923	3.65	4.06	1.22	8.17	8.98	9.19
1997	7.57	8.42	2.52	16.53	18.18	18.84	6.6%	2.050	3.69	4.11	1.23	8.06	8.87	9.19
1998	8.13	9.03	2.71	17.34	19.08	20.08	6.6%	2.185	3.72	4.13	1.24	7.94	8.73	9.19
1999	8.69	9.64	2.90	18.16	19.98	21.41	6.6%	2.330	3.73	4.14	1.24	7.80	8.58	9.19
2000	9.25	10.25	3.08	18.98	20.88	22.69	6.0%	2.469	3.75	4.15	1.25	7.69	8.45	9.19
2001	9.94	11.00	3.31	19.92	21.92	24.05	6.0%	2.618	3.80	4.20	1.27	7.61	8.37	9.19
2002	10.69	11.81	3.56	20.91	23.01	25.49	6.0%	2.775	3.85	4.25	1.28	7.54	8.29	9.19
2003	11.48	12.67	3.83	21.96	24.15	27.02	6.0%	2.941	3.90	4.31	1.30	7.47	8.21	9.19
2004	12.34	13.60	4.11	23.05	25.35	28.64	6.0%	3.118	3.96	4.36	1.32	7.39	8.13	9.19
2005	13.27	14.59	4.42	24.19	26.61	30.36	6.0%	3.305	4.01	4.42	1.34	7.32	8.05	9.19
2006	14.26	15.66	4.75	25.40	27.94	32.19	6.0%	3.503	4.07	4.47	1.36	7.25	7.98	9.19
2007	15.32	16.81	5.11	26.66	29.33	34.12	6.0%	3.713	4.13	4.53	1.38	7.18	7.90	9.19
2008	16.47	18.04	5.49	27.99	30.78	36.16	6.0%	3.936	4.18	4.58	1.39	7.11	7.82	9.19
2009	17.70	19.36	5.90	29.38	32.32	38.33	6.0%	4.172	4.24	4.64	1.41	7.04	7.75	9.19
2010	19.02	20.77	6.34	30.84	33.92	40.63	6.0%	4.422	4.30	4.70	1.43	6.97	7.67	9.19
2011	20.45	22.29	6.82	32.37	35.61	43.07	6.0%	4.688	4.36	4.76	1.45	6.91	7.60	9.19
2012	21.98	23.93	7.33	33.98	37.38	45.66	6.0%	4.969	4.42	4.82	1.47	6.84	7.52	9.19

3.1.4 - The Social Discount Rate

A key parameter in the supply price analysis is the social opportunity cost of capital, or real social discount rate. Typically, it is set at values of 10% (Jenkins, 1977 or Treasury Board, 1976), 7% (Burgess, 1981) or 4% (Ontario Hydro). The Ministry of Energy has selected 5% for the base calculations.*

3.2 - Results

The aggregated results of the base case economic analysis are shown in Table 3.2 and Figure 3.2, and detailed project specific results are contained in Appendix C. The total economic potential is 3833 MW, or about 38% of the technical potential (9962 MW) discussed Chapter 2. An analysis of economic potential by sector and heat demand category indicates the following.

(a) About 51% (or 1942 MW) of the total economic potential is in the industrial sector, and 34% in the residential sector. The commercial sector accounts for an additional 12% with the remaining 3% in the institutional sector. Given the base case economic parameters, only the shopping mall subsector and the low heat demand category for non-pulp and paper industries show no economic potential.

(b) Within the industrial sector, the greatest economic potential is in the pulp and paper, chemicals, and petroleum products industries, accounting for respectively 20%, 14% and 12% of the sectoral total.

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* As discussed in Appendix A, a higher real discount rate would enhance the economic cost-competitiveness of cogenerated electricity relative to conventional bulk power generation.

TABLE 3.2

TOTAL COGENERATION POTENTIAL

(Base Case - Wood/Gas Fuel Option and Base Case Prices)

Sector Sub-Sector	Heat Demand Category	Total Economic Potential (MW)
Industrial		
- Pulp & Paper	Low	4.6
	Medium	8.2
	High	385.2
- Iron & Steel	High	177.9
- Mining & Smelting	High	57.1
- Petroleum Product	High	230.5
- Chemicals	High	262.6
- All Other	Low	0.0
	Medium	460.0
	High	356.3
Total Industrial		1942.3
Institutional		
- Universities	Medium	14.4
	High	18.0
- Hospitals	Medium	78.0
Total Institutional		110.4
Commercial		
- Shopping Malls	Medium	0.0
- Offices	Medium	459.0
Total Commercial		459.0
Residential		
- Apartments	Low	1321.5
Total Residential		1321.5
TOTAL ALL SECTORS		3833.2

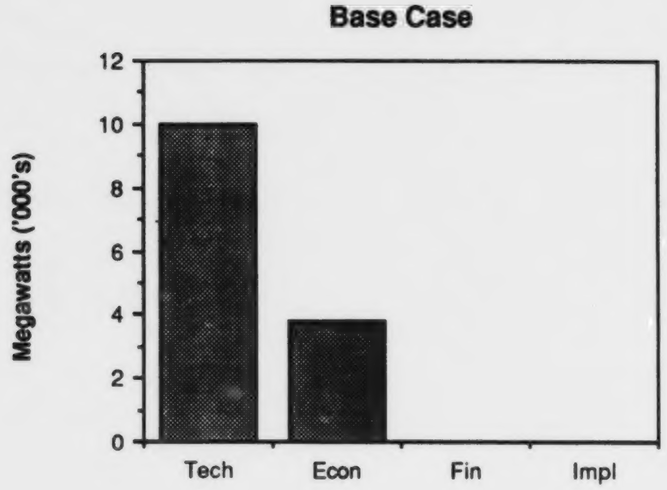

Figure 3.2
COGENERATION POTENTIAL IN ONTARIO

BASE CASE

(c) Also within the industrial sector, the high heat demand category offers the greatest scope for economic cogeneration, accounting for 76% of the total. The medium heat category represents virtually the entire remaining potential.

(d) The economic potential for industrial cogeneration is similar to the earlier estimates reviewed in Chapter 1. The inclusion of the low and medium heat categories had a significant impact in raising technical potential, but no corresponding effect in increasing the economic potential.

(e) In the residential sector, the economic potential for cogeneration in multi-unit apartment buildings exceeding 200 units per building totals 1321.5 MW.

4 - FINANCIAL POTENTIAL

4 - FINANCIAL POTENTIAL

4.1 - Approach and Assumptions

4.1.1 - Evaluation Criteria

The supply price analysis utilized in the assessment of economic potential adopts the public or provincial perspective. It is therefore vital in the development of energy policy and efficient resource allocation. Financial potential is reflective of the investor's point of view and as a result adopts a much narrower perspective. The methods and criteria in this analysis differ in several respects from those associated with the supply price analysis. (Figure 3.1 provides an overview of the model used in the financial analysis.)

Typically, the private investor can be concerned with either of two criteria. The most common yardstick is the simple (undiscounted) payback period. This measures the number of years required to accumulate sufficient cash flow to equal the initial investment. The maximum acceptable payback period depends on the nature of project ownership, with industrial and other private investors generally requiring a payback of 5 years or less. A second, and less common indicator, is the discounted cash flow (DCF) return on equity investment over the investment horizon of the project. The annual return to equity is annual net cash flow after taxes and after debt servicing (principal and interest repayments on debt capital). This yardstick has the conceptual advantage of not ignoring cash flows occurring after the payback period, and the practical advantage of affording a ready comparison of yields vis-a-vis other productive and financial investment opportunities. Depending again on the type of project ownership, the required after-tax or "hurdle" rate of return is 15% to 20% in real terms. The impacts of more and less stringent investment criteria are analyzed in Chapter 7.

4.1.2 - Cost Base

Financial analysis is performed on the basis of nominal (current) dollar cash flows. Since financing cost (interest rates, cost of equity, etc) are denominated in nominal terms, the investment decision-maker will also require a nominal dollar financial analysis. The real (1981) dollar capital and non-energy operating costs used in the economic analysis are escalated to current dollars by the consumer price index (CPI). Table 3.1 lists the CPI values used in the analysis.

Adjustments to the base costs, not included in the supply price analysis, must be considered in the financial analysis to accommodate the numerous applicable transfer payments. The most significant transfer payments are: capital grants, capital cost allowances and income taxes.

Investment Grants

Investment grants involve a direct reduction in the capital cost of cogeneration facilities. A secondary impact is to reduce debt service requirements. In this study, the base case analysis includes no capital grants. The impact analysis, shown in Chapter 7, considers an alternative case involving investment grants.

Capital Cost Allowances

Capital cost allowances (CCA) are deducted from net income in the calculation of income tax payable. An accelerated capital cost allowance results in an earlier capital recovery than does a normal CCA. Cogeneration equipment qualifies under Class 34 and, as such, can be depreciated for tax purposes over three years at 25%, 50% and 25%, respectively.

Income Tax

Income taxes are calculated at 50% of net income before taxes for all but the institutional sector, which is not subject to income tax.

4.1.3 - Energy Prices

The financial analysis is concerned with the market price of energy, rather than the supply prices used in the economic analysis. The benefits of a cogeneration project are defined by the actual dollar value of electricity saved or produced. The value associated with electricity saved, i.e. electricity which is now produced internally rather than purchased from a utility, is based on the market price for electricity. The value of electricity in excess of internal requirements and assumed sold to the local utility is based on Ontario Hydro's buyback or purchased power rate. All prices are expressed in nominal (current) dollar terms.

The nominal market prices are determined as the real price (see Section 3.1.2) times the annual CPI factor for the appropriate year. The buyback rate is escalated by the CPI from the 1986 figure of 3.45//kW.h. Table 3.1 shows the nominal fuel prices used in the base case analysis over the study planning horizon. As in the supply price analysis, the price for wood waste is computed as one third of the natural gas price. The impact analyses of alternative market prices of energy and higher buyback rates are shown in Chapter 7.

4.1.4 - Planning Horizon

The owner's investment horizon is sensitive to factors other than the economic life of the equipment. In this study, the financial analysis is conducted using the pre-tax payback period, a base year of 1985, and a one year construction period (in 1987). For ROI calculations (see

Section 4.1.1), a planning period of 8 years is used, corresponding to the debt amortization period.

4.1.5 - Interest Rate

In place of the real social discount rate, the financial analysis uses the market cost of capital as a measure of the "time value of money". For debt capital, nominal interest rates and amortization periods are used to compute levels of debt servicing and the values of various investment indicators. A debt-equity ratio of 50% and a nominal cost of debt capital of 10% are used in this study.* Debt principal is repaid in equal amounts over the amortization period of the loan.

4.2 - Results

The aggregated results of the base case financial analysis are shown in Table 4.1 and Figure 4.1, and the detailed project-specific results are contained in Appendix C. The total financial potential is 1677 MW, or about 17% and 44% of the estimated technical and economic potentials respectively. An analysis of financial potential by sector and heat demand category indicates the following:

(a) About 99% of the financial potential is in the industrial sector and 1% in the institutional sector. In contrast, the industrial sector accounted for 'only' 38% of the total technical potential.

(b) Within the industrial sector, the greatest financial potential is found in the pulp and paper industry (24% of the industrial total), the chemicals industry (15%) and the petroleum products industry (14%).

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* The cost of debt corresponds to a real interest rate of 4 to 5%.

(c) Also, within the industrial sector over 70% of the financial potential stems from the high heat demand category. The medium heat category offers a financial potential of 468 MW.

(d) In comparison to earlier estimates of financial potential in industry (see Chapter 1), the results indicate significantly greater scope for projects meeting the financial criterion of 5-year payback or less. This stems from lower natural gas prices and lower 1985 dollar capital costs than those used in earlier analyses.

(e) In the institutional sector, all of the financial potential (18 MW) is represented by the high heat demand category in the universities subsector.

TABLE 4.1

TOTAL COGENERATION POTENTIAL

(Base Case - Wood/Gas Fuel Option and Base Case Prices)

Sector Sub-Sector	Heat Demand Category	Total Potential Economic (MW)	Total Potential Financial (MW)
Industrial			
- Pulp & Paper	Low	4.6	0.0
	Medium	8.2	8.2
	High	385.2	385.2
- Iron & Steel	High	177.9	160.2
- Mining & Smelting	High	57.1	37.4
- Petroleum Product	High	230.5	230.5
- Chemicals	High	262.6	244.4
- All Other	Low	0.0	0.0
	Medium	460.0	460.0
	High	356.3	133.0
Total Industrial		1942.3	1658.9
Institutional			
- Universities	Medium	14.4	0.0
	High	18.0	18.0
- Hospitals	Medium	78.0	0.0
Total Institutional		110.4	18.0
Commercial			
- Shopping Malls	Medium	0.0	0.0
- Offices	Medium	459.0	0.0
Total Commercial		459.0	0.0
Residential			
- Apartments	Low	1321.5	0.0
Total Residential		1321.5	0.0
TOTAL ALL SECTORS		3833.2	1676.9

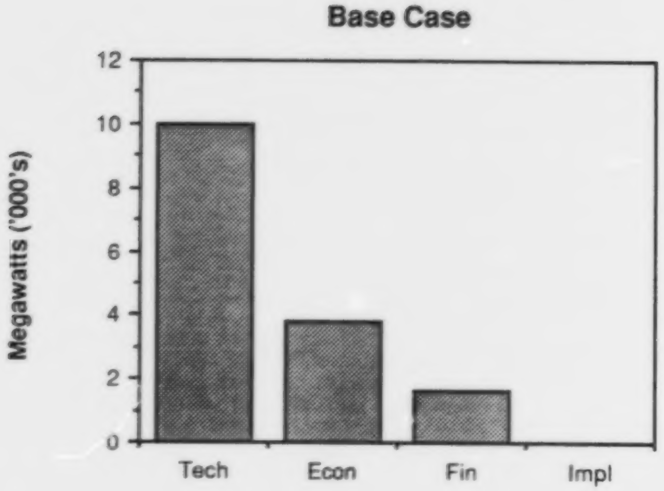

Figure 4.1
COGENERATION POTENTIAL IN ONTARIO

BASE CASE

5 - IMPLEMENTATION POTENTIAL

5 - IMPLEMENTATION POTENTIAL

5.1 - Approach and Assumptions

Technical, economic and financial feasibility are necessary, but not sufficient conditions, to ensure the implementation of cogeneration technology. Implementation requires that additional or more stringent criteria be satisfied.

Industrial Sector

It is estimated that industrial boilers have a useful life of 20 years and, hence, all of the boiler population will be replaced by the end of the study horizon. In this respect, the implementation potential can be expected to equal the financial potential. However there are other constraints to the realization of the financially feasible opportunities. As outlined in Chapter 6, barriers to cogeneration development include a use of stringent payback criteria that reflect institutional reluctance to become a power generator. The reluctance of industry to install cogeneration equipment is confirmed by the fact that no new projects have been implemented in the past 10 years despite earlier findings that 20 out of 59 large projects were financially feasible with paybacks of less than 5 years.* Although no single criterion will fully measure the implementation potential, the use of a more stringent 3-year payback period is suggested for base case analysis.**

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* See Diener and Dupont (1984), Acres Shawinigan (1979)

** Surveys designed to identify industrial criteria for implemented (as opposed to financially viable) conservation projects point to 3 years as the maximum payback period. See Armstrong (1979).

Non-industrial Sectors

As in the industrial sector, earlier studies have identified several financially feasible projects that have not yet been implemented. (The barriers impeding the development of cogeneration are discussed in Chapter 6). However, we are not aware of any surveys that have pinpointed the criteria met by implemented projects in the commercial, institutional and residential sectors. It will, therefore, be assumed that the same implementation criterion applies as in the industrial sector (3-year payback period).

5.2 - Results

The aggregated results of the base case analysis are shown in Table 5.1 and Figure 5.1. Detailed project-specific results are contained in Appendix C. The total implementation potential is approximately 1347 MW, or about 14%, 35% and 80% of the technical, economic and financial potentials, respectively. An analysis of implementation potential by sector and heat demand category indicates the following.

(a) All of the potential is accounted for by the high and medium heat demand categories of the industrial sector.

(b) The indicated potential exceeds many of the earlier estimates. This is a result of lower fuel prices and equipment costs relative to those used in previous studies.

(c) Within the industrial sector, implementation potential is found in the pulp and paper industry (22% of the industrial potential), chemicals (16%) and petroleum products (14%). Thirty-four percent of the total potential is generated in the medium industrial capacity.

These results reflect the sensitivity of estimated potentials to the choice of payback period. In particular, it is noteworthy that replacing the 5-year payback criterion used to measure financial potential by a 3-year figure applicable to implementation potential, the estimated scope for cogeneration drops by approximately 330 MW. The payback requirement is clearly an important barrier to implementation and will be discussed further in Chapters 6 and 7.

TABLE 5.1

TOTAL COGENERATION POTENTIAL

(Base Case - Wood/Gas Fuel Option and Base Case Prices)

Sector Sub-Sector	Heat Demand Category	---- Total	Cogeneration Potential	---
		Economic (MW)	Financial (MW)	Implementation (MW)
Industrial				
- Pulp & Paper	Low	4.6	0.0	0.0
	Medium	8.2	8.2	0.0
	High	385.2	385.2	301.3
- Iron & Steel	High	177.9	160.2	105.6
- Mining & Smelting	High	57.1	37.4	37.4
- Petroleum Product	High	230.5	230.5	194.4
- Chemicals	High	262.6	244.4	217.8
- All Other	Low	0.0	0.0	0.0
	Medium	460.0	460.0	460.0
	High	356.3	133.0	30.1
Total Industrial		1942.3	1658.9	1346.7
Institutional				
- Universities	Medium	14.4	0.0	0.0
	High	18.0	18.0	0.0
- Hospitals	Medium	78.0	0.0	0.0
Total Institutional		110.4	18.0	0.0
Commercial				
- Shopping Malls	Medium	0.0	0.0	0.0
- Offices	Medium	459.0	0.0	0.0
Total Commercial		459.0	0.0	0.0
Residential				
- Apartments	Low	1321.5	0.0	0.0
Total Residential		1321.5	0.0	0.0
TOTAL ALL SECTORS		3833.2	1676.9	1346.7

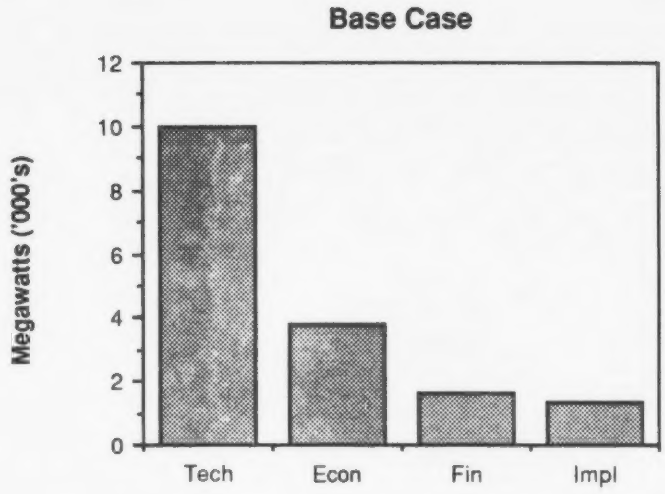

Figure 5.1
COGENERATION POTENTIAL IN ONTARIO

BASE CASE

6 - BARRIERS TO COGENERATION DEVELOPMENT

6 - BARRIERS TO COGENERATION DEVELOPMENT

6.1 - Introduction

Several earlier cogeneration studies discussed the barriers facing implementation of economically sound projects. This chapter reviews these studies and additional information assembled from interviews of interested energy consumers, energy consultants and equipment suppliers. The analysis of alternative measures to reduce the impact of these barriers also draws on the consultants' experience in the study and development of programs and measures aimed at accelerating adoption of economically efficient investments in energy productivity. Section 6.1 provides a description of the various barriers affecting cogeneration. Section 6.2 turns to alternative measures designed to overcome these barriers.

6.2 - Barriers to Realization of Potential

The barriers to development of cogeneration were examined based on (1) review of literature and previous study commentary on the subject, and (2) 13 telephone interviews with persons knowledgeable about cogeneration. In 1981 and 1982, Ontario Hydro conducted and commissioned a series of plant-specific feasibility studies. The interviews included personnel from these plants to determine current developments and attitudes. Table 6.1 indicates the types of organizations covered by the telephone interviews. Notes on each interview are contained in this report as Appendix D.

TABLE 6.1

SCOPE OF TELEPHONE INTERVIEWS

Type of Organization	Number of Organization Interviewed
Mining	1
Food and Beverage	2
Paper and Allied Products	3
Transportation Equipment	1
Chemicals	1
Petroleum Products	1
Hospitals	1
Cogeneration Equipment Supplies	2
Cogeneration Consultants (residential and commercial and institutional buildings)	1
Total	13

The institutional barriers to cogeneration were discussed at some length in a 1979 Canada-wide study on cogeneration.* It may be useful to state the principal findings at that time; little has changed since then; almost no cogeneration has been developed over the 1979 to 1986 period. The findings were

- economics are still the major determining factor

- joint ventures could be a trend in future

- providing direct financial incentives appears to be the most direct route to encourage industrial cogeneration

- existing attitudes to cogeneration appear to be a major obstacle

- government could improve coordination and act as catalysts

- development of demonstration projects is required to promote action.

Our recent interviews, and recent analysis indicate that the most important of these barriers are attitudes and economics.

The attitudes described in the 1979 study are pervasive. Industry's attitude is that "electricity is not our business". The attitude of Ontario Hydro and the local utilities is perceived to be that "electricity is exclusively our business".

The fully centralized position occupied by Ontario Hydro may be the greatest institutional barrier. The situation differs from the US, where there exist area and regional utilities, many privately owned although publicly regulated. The Public Utilities Regulatory Policies

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* Prepared by Acres Shawinigan for Energy, Mines and Resources Canada.

Act (PURPA) has also created a positive environment and a workable arrangement for the reintroduction of cogeneration.

Based on our literature review, and interviews, we conclude that cogeneration developments have been impeded by a lack of enthusiasm towards cogeneration exhibited by Ontario Hydro.

While parallel generation interconnection requirements have recently been established, and are available in published form from Ontario Hydro, these requirements have not been market tested. The underlying assumptions and analyses have not been developed in a consultative manner; hence it is not clear whether the requirements are too stringent or indeed whether they address the questions felt to be important by industry.

Rates for the purchase by the grid of electricity from cogeneration were based until 1985 on the average cost of generation. Modifications at that time raised the rates substantially. The lack of development of cogeneration projects to date may indicate either the long lag time between the rise in rates and the development of projects, or the fact that the new rates are still not sufficient, with all the other conditions as they exist, to encourage cogeneration.

The role of natural gas is also unclear. From the parallel generation guidelines, it appears that the emphasis is on renewable fuels. Both earlier studies and the present one indicate that natural gas-fired steam and gas turbines may frequently be the preferred technical choice.

From the interviews, the distinct impression was that many industries do not feel comfortable with Ontario Hydro. Some of this has to do with the lack of clearly stated industrial arrangements. This may be due to the fact that Ontario Hydro is still exploring cogeneration.

There is general awareness, fostered by public and media debates, that the Government and Ontario Hydro do not place equal emphasis on bulk generation and parallel generation. In effect, industry seems to be saying that the institutional framework for the development of cogeneration is not in place in Ontario to the extent necessary to gain the active participation of industry.

Attitudinal barriers also include industry's reluctance to become power producers. Although, as shown below, economics play a part in this reluctance, much of it has to do with the perceived risks of a technology that has not yet gained wide penetration in the industrial and buildings sectors.

It is difficult to 'sell' cogeneration to industrial or commercial customers without encouragement provided by cogeneration systems in similar establishments.

Turning to economics it was noted, from the industry interviews, that in many instances a company's energy requirement - particularly steam-has changed significantly in just a few years. This is typical of many manufacturing industries that need to make constant adjustments due to changing general economic situations, including world commodity prices, markets, products, processes and competitive positions, to remain profitable; hence, the insistence on short payback periods for their investments. Risk minimization seems to be an overriding consideration.

Payback criteria seem to be the dominant economic barrier. The interviews confirmed that a 3 year payback i- generally required but not apparently met by cogeneration projects. In this respect, cogeneration projects face the same barrier as energy conservation investments.

Unlike the issue of payback, the question of capital availability was not mentioned frequently although it may be that this was outside the typical frame of reference of the more technically-oriented respondents. The general impression was gained that if a project makes economic sense it is therefore, by definition, beneficial to the company and will be treated similarly to - sometimes a little better than - other projects competing for investment dollars. Of course, in retrenching industries, or plants, the matter of investments may well be an academic one.

Having recently gone through another major energy oil price upheaval, and to a lesser extent gas, when considering deregulated prices, the question of forecasting price movements - absolute as well as relative - has become a complex, and at times confusing, exercise which can add tremendously to the risk of the cogeneration decision. A policy question is how government initiative could reduce these and other perceived risks inherent in cogeneration.

Frequent mention was also made of how well the United States seems to have tackled the problem. Granted, their power generation economics are, in general, more favorable for cogeneration. Yet the US experience has examples of policy initiatives that seem to have worked. For instance, low-cost parallel generation has been stimulated by PURPA rules that require utilities to pay full avoided cost for cogeneration electricity.

Technology, construction, planning, environmental aspects and operational matters appear to have little bearing on the cogeneration decision. With appropriate skills, they can all be overcome by normal implementation methods.

6.3 - Policy Options to Overcome Barriers

6.3.1 - Pricing

A necessary (though not sufficient) condition for the economic and financial potentials to be equal is that energy market prices reflect supply prices* as defined by long-run economic costs. In the base case analysis, the prices of fuels and wood waste were assumed to meet this condition. However, in the case of electricity, it is less certain that the various prices used in the analysis (buyback rates and average market prices) do in fact reflect the long-run economic costs of Ontario Hydro. If long-run costs exceed the purchase and/or sales prices of electricity, there will remain a disincentive to the implementation of cogeneration projects. An example of the impact of higher buyback rates on financial and implementation potentials is shown in Chapter 7. An even more fundamental and controversial issue is whether Ontario Hydro's sales price of electricity is less than its long-run cost of generation. The current study scope excludes this issue; however, the impact of a hypothetical increase in these prices is also shown in Chapter 7.

6.3.2 - Financial Incentives

A major barrier to the development of cogeneration projects has been identified as its high payback period in relation to the investor's maximum acceptable criteria. The remedy, in a situation where even a 6-year payback (about 17% return) is unacceptable, could involve a number of options. One option is selective financial incentives so economically feasible projects achieve approval target paybacks (about 3 years). Another option, discussed in Section 6.3.3, would be a technology transfer program to reduce the perceived risks of cogeneration and encourage the use of less stringent payback criteria.

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* Refer to Section 3.1.1 of this study.

The option of financial incentives could take the form of

(a) investment grants
(b) investment tax credits
(c) output price guarantees
(d) loan guarantees and
(e) accelerated depreciation.

Of these, (e) is in place, offering fast (3-year) write-off for cogeneration equipment. The other types of financial incentives are compared in Table 6.2. Alternative (a) - investment grants - offers a straightforward and flexible means of reducing the payback period to acceptable levels, however, it is potentially a very expensive program. To ensure its cost-effectiveness, this type of incentive could be designed such that

(i) only economically viable projects would qualify, (based on the criterion of a competitive electricity supply price), and

(ii) the grant is 'capped' at 20% of approved capital cost or the amount required to achieve a payback of 3 years, whichever is lower.

An example of the impact of a 20% investment grant is shown in Chapter 7.

6.3.3 - Information and Demonstration Programs

The analysis of barriers has identified institutional issues as an important obstacle to the implementation of cogeneration projects. To overcome these types of barriers, the option of providing 'soft' incentives may be added to the options of the alternative pricing and fiscal measures outlined above. Soft incentives include information and demonstration programs whose benefits include the following.

TABLE 6.2

COMPARISON OF ALTERNATIVE FISCAL INCENTIVES

	Advantages	Disadvantages
(a) Investment Grants	Shortens the payback period. Flexibility and selectivity in terms of targeting eligible projects.	Potentially a high-cost program.
(b) Investment Tax Credits	Tax expenditures may meet less resistance than direct government spending.	No impact on pre-tax payback period. No impact on institutional (tax-free) sector.
(c) Output (electricity) Price Guarantees	Reduces financial risk inherent in uncertain output prices and shortens the payback period.	Complex to administer. Applicable only where excess power and energy is produced.
(d) Loan Guarantees	Low-cost program.	No impact on pre-tax payback period.

- The programs indicate government's commitment and leadership role in coordinating the efforts of interested parties.

- Information and publicity programs create sector-specific awareness and interest by providing regular updates on the latest and most cost-effective technologies, case studies of successful applications and generic examples of financially feasible installations.*

- Demonstration projects would be effective both as a transfer of technology across a subsector and as a means of reducing the perceived technical and financial risks of cogeneration.*

In all of these policy options, there is a variety of possible roles that may be played by the Ministry, Ontario Hydro and the Ontario Energy Board.

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* An example of industry's interest in these initiatives is the fact that information/demonstration programs were ranked first by a wide margin out of several proposed energy management programs at a recent energy seminar. See summary of Policy Workshop Proceedings, Energy Forum 1986, Pollution Probe Foundation, Toronto, February 1986.

7 - IMPACT ANALYSIS

7 - IMPACT ANALYSIS

7.1 - Introduction

This chapter describes the sensitivity of cogeneration potential to changes in the principal evaluation criteria. The quantitative analysis described thus far in the study assumes prices, costs and required payback periods as shown in Chapters 3, 4, and 5. This chapter makes use of alternative assumptions in key areas as shown in Table 7.1. Sections 7.2 to 7.7 describe the assumptions and results of the six alternative cases. Appendix C provides detailed results on a project specific basis.

The analysis examines the impacts on cogeneration potential for six alternative pricing and policy scenarios, including those essentially external to the Province (for example, oil and natural gas pricing) and those that may be shaped within Ontario (for example, buyback rates).

Table 7.2 summarizes economic, financial and implementation potential for all six sensitivity cases in comparison to the base case results.

TABLE 7.1

SUMMARY OF IMPACT CASES

	Type of Cogeneration Potential Impacted		
	Economic	Financial	Implementation
1 - Lower Energy Prices[1]	X	X	X
2 - High Electricity Price[2]	X	X	X
3 - Higher Buyback Rates[3]		X	X
4 - Investment Grants[4]		X	
5 - Higher Maximum Payback Period[5]		X	X
6 - Lower Maximum Payback Period[6]		X	X

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[1] Lower growth rates in real market prices of natural gas, electricity and wood waste and in real shadow prices of natural gas and wood waste. Lower growth rate in consumer price index and hence in nominal (current) dollar buyback rates.

[2] Ratio of electricity price (¢/kW.h) and natural gas price ($/GJ) maintained at 2:1 (rule of thumb criterion for financial feasibility quoted in Shalaby, 1986).

[3] Base period buyback rates increased by 20%.

[4] Twenty percent investment grant for projects whose payback periods exceed 3 years.

[5] Less stringent payback requirement of 8 and 5 years for financial and implementation viability, respectively.

[6] More stringent paybacks of 3 and 2 years for financial and implementation viability.

TABLE 7.2

SUMMARY OF COGENERATION POTENTIAL

	---- Cogeneration Potential (MW)[1] ----		
	Economic	Financial	Implementation
Base Case	3833.2	1676.9	1346.7
	51%	99%	100%
Sensitivity Cases			
Case 1	3833.2	1707.0	1415.6
	51%	99%	99%
Case 2	3833.2	3802.7	3211.5
	51%	50%	55%
Case 3	3833.2	1748.0	1346.7
	51%	99%	100%
Case 4	3833.2	1818.7	1489.6
	51%	99%	99%
Case 5	3833.2	1951.8	1676.9
	51%	95%	99%
Case 6	3833.2	1346.7	360.6
	51%	100%	100%

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[1] Figures expressed as percentages denote the industrial sector's share of the total provincial potential.

7.2 - Lower Energy Prices (Case 1)

The price forecasts associated with this scenario are based on lower energy price projections. The nominal prices for industrial natural gas and electricity display annual average growth rates of 3.5% and 3.7% respectively. In the base case these rates are 6.3% and 5.2%. The price forecasts are shown in Table 7.3. Forecasts of the CPI and the real ($1985) dollar prices used in the analysis of financial and implementation potentials for these sectors are also shown in this table.

The estimated economic, financial and implementation potentials are summarized in Table 7.4 and Figure 7.1. The financial potential is 1707 MW, an increase of approximately 2% relative to the base case analysis and approximately 45% of the economically feasible capacity. The additional financial potential stems entirely from the miscellaneous industry group whose potential is up 66 MW.

The implementation potential is more sensitive to lower price projections. It is estimated at 1416 MW, an increase of 5% compared to the base case. In the impact case, this potential represents 37% of the economically feasible cogeneration capacity.

TABLE 7.3

NOMINAL AND REAL FUEL PRICE CALCULATIONS - Lower Energy Prices

Year	Nominal Fuel Prices ($/GJ)						Escalation		Real Fuel Prices ($/GJ)					
	Natural Gas		Wood	Electricity			Annual	Annual	Natural Gas		Wood	Electricity		
	Ind	Comm	Waste	Ind	Comm	Buy Back	CPI	Factor	Ind	Comm	Waste	Ind	Comm	Buy Back
1985	4.19	4.63	1.40	8.79	11.26	9.17	4.5%	1.000	4.19	4.63	1.40	8.79	11.26	9.17
1986	4.08	4.70	1.36	9.14	11.72	9.58	2.1%	1.021	4.00	4.60	1.33	8.95	11.48	9.39
1987	3.75	4.37	1.25	9.58	12.29	9.83	2.6%	1.048	3.58	4.17	1.19	9.15	11.73	9.39
1988	3.71	4.35	1.24	10.09	12.94	10.15	3.2%	1.081	3.43	4.02	1.14	9.33	11.97	9.39
1989	3.88	4.53	1.29	10.55	13.54	10.51	3.6%	1.120	3.46	4.04	1.15	9.42	12.09	9.39
1990	4.11	4.79	1.37	11.08	14.20	10.92	3.9%	1.164	3.53	4.12	1.18	9.52	12.20	9.39
1991	4.44	5.15	1.48	11.48	14.71	11.35	3.9%	1.209	3.67	4.26	1.22	9.49	12.17	9.39
1992	4.77	5.50	1.59	11.88	15.22	11.79	3.9%	1.256	3.80	4.38	1.27	9.45	12.12	9.39
1993	5.10	5.86	1.70	12.27	15.74	12.25	3.9%	1.305	3.91	4.49	1.30	9.40	12.06	9.39
1994	5.43	6.21	1.81	12.67	16.25	12.73	3.9%	1.356	4.00	4.58	1.33	9.34	11.98	9.39
1995	5.76	6.57	1.92	13.07	16.76	13.25	4.1%	1.412	4.08	4.65	1.36	9.26	11.87	9.39
1996	5.98	6.83	1.99	13.57	17.40	13.79	4.1%	1.470	4.07	4.65	1.36	9.23	11.84	9.39
1997	6.20	7.09	2.07	14.07	18.05	14.36	4.1%	1.530	4.06	4.63	1.35	9.20	11.80	9.39
1998	6.43	7.35	2.14	14.57	18.69	14.95	4.1%	1.593	4.04	4.62	1.35	9.15	11.74	9.39
1999	6.65	7.61	2.22	15.07	19.34	15.56	4.1%	1.658	4.01	4.59	1.34	9.09	11.66	9.39
2000	6.87	7.87	2.29	15.57	19.98	16.20	4.1%	1.726	3.98	4.56	1.33	9.02	11.58	9.39
2001	7.12	8.16	2.37	16.12	20.69	16.86	4.1%	1.797	3.96	4.54	1.32	8.98	11.52	9.39
2002	7.37	8.46	2.46	16.70	21.44	17.55	4.1%	1.870	3.94	4.52	1.31	8.93	11.46	9.39
2003	7.64	8.77	2.55	17.29	22.20	18.27	4.1%	1.947	3.92	4.50	1.31	8.88	11.40	9.39
2004	7.91	9.09	2.64	17.91	23.00	19.02	4.1%	2.027	3.90	4.49	1.30	8.84	11.35	9.39
2005	8.19	9.43	2.73	18.55	23.82	19.80	4.1%	2.110	3.88	4.47	1.29	8.79	11.29	9.39
2006	8.49	9.77	2.83	19.21	24.67	20.62	4.1%	2.196	3.86	4.45	1.29	8.75	11.23	9.39
2007	8.79	10.13	2.93	19.89	25.55	21.46	4.1%	2.286	3.85	4.43	1.28	8.70	11.18	9.39
2008	9.11	10.51	3.04	20.60	26.47	22.34	4.1%	2.380	3.83	4.41	1.28	8.66	11.12	9.39
2009	9.43	10.89	3.14	21.34	27.41	23.26	4.1%	2.478	3.81	4.40	1.27	8.61	11.06	9.39
2010	9.77	11.29	3.26	22.10	28.39	24.21	4.1%	2.579	3.79	4.38	1.26	8.57	11.01	9.39
2011	10.12	11.71	3.37	22.88	29.41	25.20	4.1%	2.685	3.77	4.36	1.26	8.52	10.95	9.39
2012	10.49	12.14	3.50	23.70	30.46	26.24	4.1%	2.795	3.75	4.34	1.25	8.48	10.90	9.39

TABLE 7.4

TOTAL COGENERATION POTENTIAL

**(Case 1 - Lower Energy Prices -
Wood/Gas Fuel Option and Lower Energy Prices)**

Sector Sub-Sector	Heat Demand Category	--- Total Cogeneration Potential --- Economic (MW)	Financial (MW)	Implementation (MW)
Industrial				
- Pulp & Paper	Low	4.6	0.0	0.0
	Medium	8.2	8.2	0.0
	High	385.2	385.2	314.4
- Iron & Steel	High	177.9	177.9	143.4
- Mining & Smelting	High	57.1	37.4	37.4
- Petroleum Product	High	230.5	230.5	194.4
- Chemicals	High	262.6	257.8	217.8
- All Other	Low	0.0	0.0	0.0
	Medium	460.0	460.0	460.0
	High	356.3	132.0	30.1
Total Industrial		1942.3	1689.0	1397.6
Institutional				
- Universities	Medium	14.4	0.0	0.0
	High	18.0	18.0	18.0
- Hospitals	Medium	78.0	0.0	0.0
Total Institutional		110.4	18.0	18.0
Commercial				
- Shopping Malls	Medium	0.0	0.0	0.0
- Offices	Medium	459.0	0.0	0.0
Total Commercial		459.0	0.0	0.0
Residential				
- Apartments	Low	1321.5	0.0	0.0
Total Residential		1321.5	0.0	0.0
TOTAL ALL SECTORS		3833.2	1707.0	1415.6

7.3 - Higher Electricity Price, Lower Natural Gas Price (Case 2)

A recent paper (Shalaby, 1986) refers to a simple rule of thumb as a test of the financial feasibility of cogeneration opportunities. It is suggested that feasibility requires the ratio of electricity to fuel (natural gas) prices to be 2:1 or higher (prices expressed in ¢/kW.h and $/MBtu respectively). In Ontario, this ratio is currently about 1:1. The sensitivity case considers a situation where the ratio is 2:1 throughout the forecast horizon, (based on the base case national gas prices) to determine the impact of this relative price change on economic, financial and implementation potentials. (The likelihood of these price ratios is quite low in Ontario.) The industrial/commercial and residential sector market prices corresponding to this impact case are shown in Table 7.5.

The estimated financial and implementation potentials are summarized in Table 7.6 and Figure 7.2. The financial potential is estimated at 3803 MW, an increase of 127% relative to the base case. The impact of higher electricity prices is significant as the financially feasible cogeneration capacity expressed as a fraction of technical potential rises from 17% in the base case to 38% in the impact case. All sectors show financial potential in this case, industry accounting for 50% residential for 35%, commercial for 12% and institutional for the remaining 3.1%.

The implementation potential is 3212 MW (up 139% from the base case). The potential represents 32% of what is technically feasible; this is the highest potential obtained in the impact analyses. All but the commercial subsectors contribute to this potential with industry accounting for 55% of the total.

TABLE 7.5

NOMINAL AND REAL FUEL PRICE CALCULATIONS - High Electricity Prices

Year	Nominal Fuel Prices ($/GJ)						Escalation		Real Fuel Prices ($/GJ)					
	Natural Gas		Wood	Electricity			Annual	Annual	Natural Gas		Wood	Electricity		
	Ind	Comm	Waste	Ind	Comm	Buy Back	CPI	Factor	Ind	Comm	Waste	Ind	Comm	Buy Back
1985	4.25	4.65	1.42	23.61	25.83	9.17	4.5%	1.000	4.25	4.65	1.42	23.61	25.83	9.17
1986	4.30	4.70	1.43	23.89	26.11	9.58	4.3%	1.043	4.12	4.51	1.37	22.90	25.03	9.19
1987	4.10	4.55	1.37	22.78	25.28	10.13	5.7%	1.102	3.72	4.13	1.24	20.66	22.93	9.19
1988	4.20	4.70	1.40	23.33	26.11	10.74	6.0%	1.169	3.59	4.02	1.20	19.97	22.34	9.19
1989	4.30	4.80	1.43	23.89	26.67	11.40	6.2%	1.241	3.46	3.87	1.15	19.25	21.49	9.19
1990	4.40	4.95	1.47	24.44	27.50	12.13	6.4%	1.320	3.33	3.75	1.11	18.51	20.83	9.19
1991	4.81	5.40	1.60	26.72	30.00	12.91	6.4%	1.405	3.42	3.84	1.14	19.02	21.35	9.19
1992	5.22	5.85	1.74	29.00	32.50	13.74	6.4%	1.495	3.49	3.91	1.16	19.40	21.74	9.19
1993	5.63	6.30	1.88	31.28	35.00	14.61	6.4%	1.591	3.54	3.96	1.18	19.66	22.00	9.19
1994	6.04	6.75	2.01	33.56	37.50	15.55	6.4%	1.692	3.57	3.99	1.19	19.83	22.16	9.19
1995	6.45	7.20	2.15	35.83	40.00	16.58	6.6%	1.804	3.58	3.99	1.19	19.86	22.17	9.19
1996	7.01	7.81	2.34	38.94	43.39	17.67	6.6%	1.923	3.65	4.06	1.22	20.25	22.56	9.19
1997	7.57	8.42	2.52	42.06	46.78	18.84	6.6%	2.050	3.69	4.11	1.23	20.51	22.82	9.19
1998	8.13	9.03	2.71	45.17	50.17	20.08	6.6%	2.185	3.72	4.13	1.24	20.67	22.96	9.19
1999	8.69	9.64	2.90	48.28	53.56	21.41	6.6%	2.330	3.73	4.14	1.24	20.72	22.99	9.19
2000	9.25	10.25	3.08	51.39	56.94	22.69	6.0%	2.469	3.75	4.15	1.25	20.81	23.06	9.19
2001	9.94	11.00	3.31	55.23	61.11	24.05	6.0%	2.618	3.80	4.20	1.27	21.10	23.35	9.19
2002	10.69	11.81	3.56	59.36	65.59	25.49	6.0%	2.775	3.85	4.25	1.28	21.39	23.64	9.19
2003	11.48	12.67	3.83	63.80	70.39	27.02	6.0%	2.941	3.90	4.31	1.30	21.69	23.93	9.19
2004	12.34	13.60	4.11	68.57	75.54	28.64	6.0%	3.118	3.96	4.36	1.32	21.99	24.23	9.19
2005	13.27	14.59	4.42	73.70	81.07	30.36	6.0%	3.305	4.01	4.42	1.34	22.30	24.53	9.19
2006	14.26	15.66	4.75	79.21	87.00	32.19	6.0%	3.503	4.07	4.47	1.36	22.61	24.84	9.19
2007	15.32	16.81	5.11	85.13	93.37	34.12	6.0%	3.713	4.13	4.53	1.38	22.93	25.15	9.19
2008	16.47	18.04	5.49	91.50	100.20	36.16	6.0%	3.936	4.18	4.58	1.39	23.25	25.46	9.19
2009	17.70	19.36	5.90	98.34	107.54	38.33	6.0%	4.172	4.24	4.64	1.41	23.57	25.78	9.19
2010	19.02	20.77	6.34	105.69	115.41	40.63	6.0%	4.422	4.30	4.70	1.43	23.90	26.10	9.19
2011	20.45	22.29	6.82	113.59	123.85	43.07	6.0%	4.688	4.36	4.76	1.45	24.23	26.42	9.19
2012	21.98	23.93	7.33	122.09	132.92	45.66	6.0%	4.969	4.42	4.82	1.47	24.57	26.75	9.19

TABLE 7.6

TOTAL COGENERATION POTENTIAL

(Case 2 - High Electricity Prices - Wood/Gas Fuel Option and Lower Energy Prices)

Sector Sub-Sector	Heat Demand Category	--- Total Cogeneration Potential --		
		Economic (MW)	Financial (MW)	Implementation (MW)
Industrial				
- Pulp & Paper	Low	4.6	4.6	0.0
	Medium	8.2	8.2	8.2
	High	385.2	385.2	385.2
- Iron & Steel	High	177.9	177.9	177.9
- Mining & Smelting	High	57.1	57.1	57.1
- Petroleum Product	High	230.5	230.5	230.5
- Chemicals	High	262.6	262.6	262.6
- All Other	Low	0.0	0.0	0.0
	Medium	460.0	460.0	460.0
	High	356.3	325.8	198.1
Total Industrial		1942.3	1911.8	1779.6
Institutional				
- Universities	Medium	14.4	14.4	14.4
	High	18.0	18.0	18.0
- Hospitals	Medium	78.0	78.0	78.0
Total Institutional		110.4	110.4	110.4
Commercial				
- Shopping Malls	Medium	0.0	0.0	0.0
- Offices	Medium	459.0	459.0	0.0
Total Commercial		459.0	459.0	0.0
Residential				
- Apartments	Low	1321.5	1321.5	1321.5
Total Residential		1321.5	1321.5	1321.5
TOTAL ALL SECTORS		3833.2	3802.7	3211.5

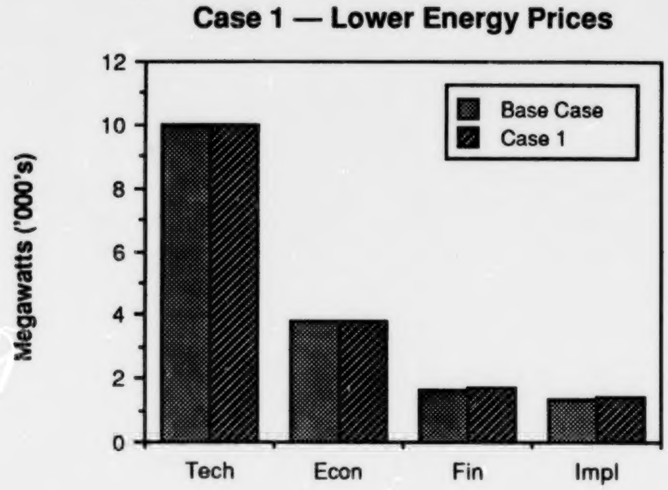

Figure 7.1
COGENERATION POTENTIAL IN ONTARIO

CASE 1 — LOWER ENERGY PRICES

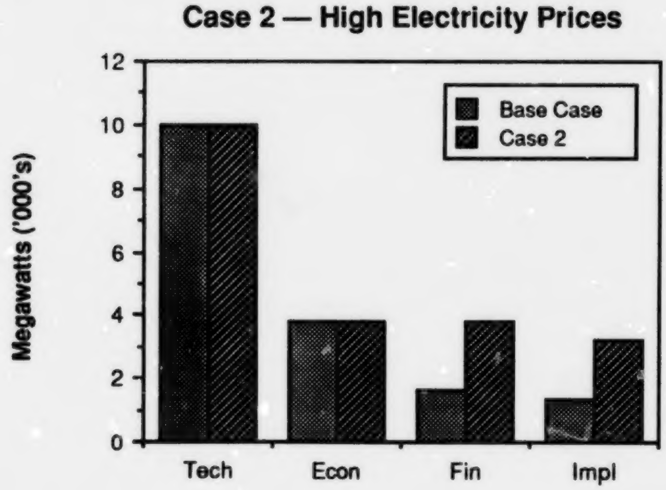

Figure 7.2
COGENERATION POTENTIAL IN ONTARIO

CASE 2 — HIGH ELECTRICITY PRICES

7.4 - Higher Buyback Rates (Case 3)

The buyback rates used in the base case analysis are surrounded by a degree of uncertainty to the extent that they are meant to reflect long-run avoided costs to Ontario Hydro. The impact case considers a situation where the buyback rate is 20% higher than in the base case, with escalation based, as before, on the CPI. The 1986 buyback rate in nominal terms rises from $.0345/kWh to $.0414/kWh.

The new estimates of financial and implementation potential are shown in Table 7.7 and Figure 7.3. Detailed results are contained in Appendix C. The financial potential was estimated at 1748 MW, an increase of 4% relative to the base case. The fraction of economic potential found to be financially feasible rose to 46% in this case.

The implementation potential is 1347 MW, unchanged from the base case analysis. All of the implementation potential stems, as in the base case, from the industrial sector.

The modest impact of higher buyback rates reflects the fact that many of potential sites would offer no surplus electricity, and that where a surplus exists, more than a 20% hike in rates would be required to achieve 3-year paybacks.

TABLE 7.7

TOTAL COGENERATION POTENTIAL

(Case 3 - Higher Buyback Rate -
Wood/Gas Fuel Option and Base Case Prices)

Sector Sub-Sector	Heat Demand Category	--- Total	Cogeneration Potential ---	
		Economic (MW)	Financial (MW)	Implementation (MW)
Industrial				
- Pulp & Paper	Low	4.6	0.0	0.0
	Medium	8.2	8.2	0.0
	High	385.2	385.2	301.3
- Iron & Steel	High	177.9	160.2	105.6
- Mining & Smelting	High	57.1	37.4	37.4
- Petroleum Product	High	230.5	230.5	194.4
- Chemicals	High	262.6	244.4	217.8
- All Other	Low	0.0	0.0	0.0
	Medium	460.0	460.0	460.0
	High	356.3	204.0	30.1
Total Industrial		1942.3	1730.0	1346.7
Institutional				
- Universities	Medium	14.4	0.0	0.0
	High	18.0	18.0	0.0
- Hospitals	Medium	78.0	0.0	0.0
Total Institutional		110.4	18.0	0.0
Commercial				
- Shopping Malls	Medium	0.0	0.0	0.0
- Offices	Medium	459.0	0.0	0.0
Total Commercial		459.0	0.0	0.0
Residential				
- Apartments	Low	1321.5	0.0	0.0
Total Residential		1321.5	0.0	0.0
TOTAL ALL SECTORS		3833.2	1748.0	1346.7

7.5 - Investment Grants (Case 4)

In the base case analysis, no investment grants were applied to the capital cost estimates. The impact case assumes that the capital costs of all projects would be reduced by a 20% investment grant. The new estimates of financial and implementation potential are summarized in Table 7.8 Figure 7.4. Detailed results are contained in Appendix C. The financial potential was estimated at 1819 MW, representing an increase of 9% relative to the base case and 47% of the economic potential shown in the impact case. As in the base case, all of the potential is contributed by the industrial sector (99%) and universities (1%).

The implementation potential is 1490 MW, up 11% or 143 MW from the base case. The increased capacity is in the industrial sector which maintains a dominant 99% share of potential.

TABLE 7.8

TOTAL COGENERATION POTENTIAL

**(Case 4 - Investment Grants -
Wood/Gas Fuel Option and Base Case Prices)**

Sector Sub-Sector	Heat Demand Category	--- Total Cogeneration Potential --		
		Economic (MW)	Financial (MW)	Implementation (MW)
Industrial				
- Pulp & Paper	Low	4.6	0.0	0.0
	Medium	8.2	8.2	8.2
	High	385.2	385.2	349.9
- Iron & Steel	High	177.9	177.9	143.4
- Mining & Smelting	High	57.1	57.1	37.4
- Petroleum Product	High	230.5	230.5	207.6
- Chemicals	High	262.6	257.8	234.9
- All Other	Low	0.0	0.0	0.0
	Medium	460.0	460.0	460.0
	High	356.3	224.1	30.1
Total Industrial		1942.3	1800.7	1471.6
Institutional				
- Universities	Medium	14.4	0.0	0.0
	High	18.0	18.0	18.0
- Hospitals	Medium	78.0	0.0	0.0
Total Institutional		110.4	18.0	18.0
Commercial				
- Shopping Malls	Medium	0.0	0.0	0.0
- Offices	Medium	459.0	0.0	0.0
Total Commercial		459.0	0.0	0.0
Residential				
- Apartments	Low	1321.5	0.0	0.0
Total Residential		1321.5	0.0	0.0
TOTAL ALL SECTORS		3833.2	1818.7	1489.6

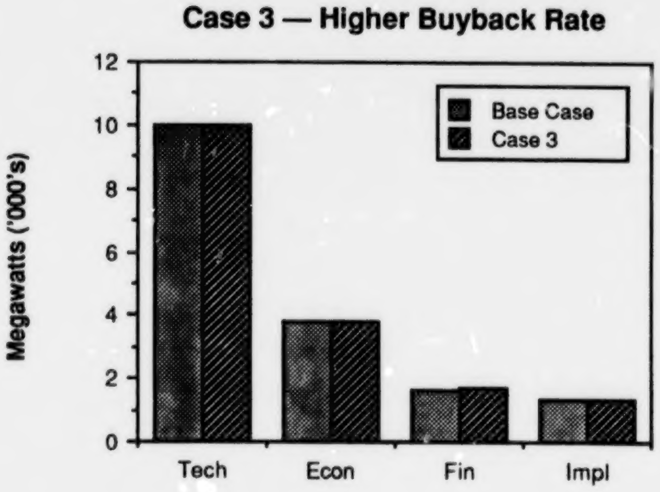

Figure 7.3
COGENERATION POTENTIAL IN ONTARIO

CASE 3 — HIGHER BUYBACK RATE

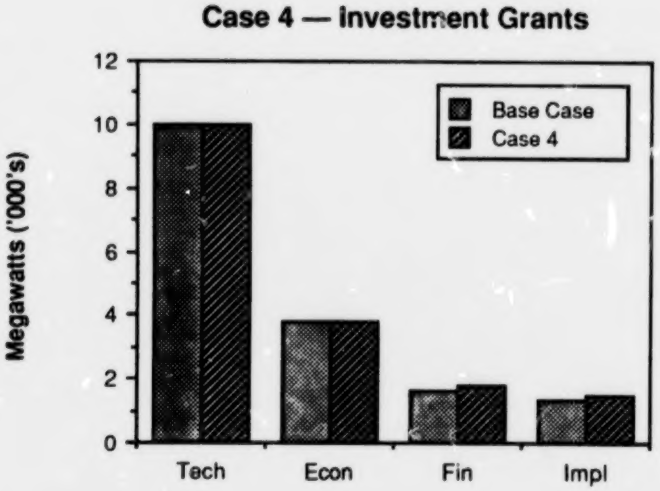

Figure 7.4
COGENERATION POTENTIAL IN ONTARIO

CASE 4 — INVESTMENT GRANTS

7.6 - Higher Maximum Payback Period (Case 5)

In the base case analysis, the criteria for financial and implementation potential were paybacks of 5 and 3 years, respectively. In the impact case, it will be assumed that these payback periods are lengthened to 8 and 5 years (offering pre-tax returns of about 12% and 20%).

Estimates of financial and implementation potential are summarized in Table 7.9 and Figure 7.5. Detailed results are contained in Appendix C. The financial potential was determined to be 1952 MW, a 16% increase relative to the base case analysis. The fraction of economic potential meeting criteria of financial feasibility rose to 51% in this case. Most of the increase in potential originates in miscellaneous industries (146 MW-increase) and hospitals (78 MW-increase).

The implementation potential is 1677 MW, an increase of 25% relative to the base case analysis. Most of the increase is accounted for by the pulp and paper industry (up 84 MW), iron and steel (up 54 MW) and petroleum products (up 36 MW). In this impact case, 44% of the economic potential would also satisfy the implementation criterion of a 5-year payback.

TABLE 7.9

TOTAL COGENERATION POTENTIAL

(Case 5 - Longer Payback Periods - Wood/Gas Fuel Option and Base Case Prices)

Sector Sub-Sector	Heat Demand Category	--- Total Cogeneration Potential --		
		Economic (MW)	Financial (MW)	Implementation (MW)
Industrial				
- Pulp & Paper	Low	4.6	0.0	0.0
	Medium	8.2	8.2	8.2
	High	385.2	385.2	385.2
- Iron & Steel	High	177.9	177.9	160.2
- Mining & Smelting	High	57.1	57.1	37.4
- Petroleum Product	High	230.5	230.5	230.5
- Chemicals	High	262.6	257.8	244.4
- All Other	Low	0.0	0.0	0.0
	Medium	460.0	460.0	460.0
	High	356.3	279.1	133.0
Total Industrial		1942.3	1855.8	1658.9
Institutional				
- Universities	Medium	14.4	0.0	0.0
	High	18.0	18.0	18.0
- Hospitals	Medium	78.0	78.0	0.0
Total Institutional		110.4	96.0	18.0
Commercial				
- Shopping Malls	Medium	0.0	0.0	0.0
- Offices	Medium	459.0	0.0	0.0
Total Commercial		459.0	0.0	0.0
Residential				
- Apartments	Low	1321.5	0.0	0.0
Total Residential		1321.5	0.0	0.0
TOTAL ALL SECTORS		3833.2	1951.8	1676.9

7.7 - Shorter Payback Period (Case 6)

This impact case considers the situation where more stringent payback criteria of 3 and 2 years apply to financial and implementation potential. As discussed in Chapter 6, there is variation around the base case values of 5 and 3 years, and hence it is reasonable to assess the impacts of both higher and lower payback periods.

The revised estimates of financial and implementation potential are summarized in Table 7.10 and Figure 7.6. Detailed results are shown in Appendix C. The financial potential was calculated to be 1347 MW, a 20% drop relative to the base case analysis. The fraction of economic potential meeting criteria of financial feasibility fell to 35% in this case. Most of the decline in potential is in the pulp and paper industry (down 95 MW), iron and steel (down 105 MW), and petroleum products (down 110 MW).

The implementation potential is 361 MW in this case, a decrease of 73% relative to the base case. This result underlines the sensitivity of potential to the choice of payback period. Lowering the acceptable payback period from 3 to 2 years leads to a 'loss' of nearly 1000 MW in implementation potential. The fraction of economic potential meeting the implementation criterion is down to 9% in this case.

A summary of the potentials associated with the range of payback criteria used in the base case and impact analyses is depicted in Figure 7.7.

TABLE 7.10

TOTAL COGENERATION POTENTIAL

(Case 6 - Shorter Payback Periods - Wood/Gas Fuel Option and Base Case Prices)

Sector Sub-Sector	Heat Demand Category	--- Total Economic (MW)	Cogeneration Financial (MW)	Potential -- Implementation (MW)
Industrial				
- Pulp & Paper	Low	4.6	0.0	0.0
	Medium	8.2	0.0	0.0
	High	385.2	301.3	206.7
- Iron & Steel	High	177.9	105.6	0.0
- Mining & Smelting	High	57.1	37.4	0.0
- Petroleum Product	High	230.5	194.4	87.8
- Chemicals	High	262.6	217.8	66.0
- All Other	Low	0.0	0.0	0.0
	Medium	460.0	460.0	0.0
	High	356.3	30.1	0.0
Total Industrial		1942.3	1346.7	360.6
Institutional				
- Universities	Medium	14.4	0.0	0.0
	High	18.0	0.0	0.0
- Hospitals	Medium	78.0	0.0	0.0
Total Institutional		110.4	0.0	0.0
Commercial				
- Shopping Malls	Medium	0.0	0.0	0.0
- Offices	Medium	459.0	0.0	0.0
Total Commercial		459.0	0.0	0.0
Residential				
- Apartments	Low	1321.5	0.0	0.0
Total Residential		1321.5	0.0	0.0
TOTAL ALL SECTORS		3833.2	1346.7	360.6

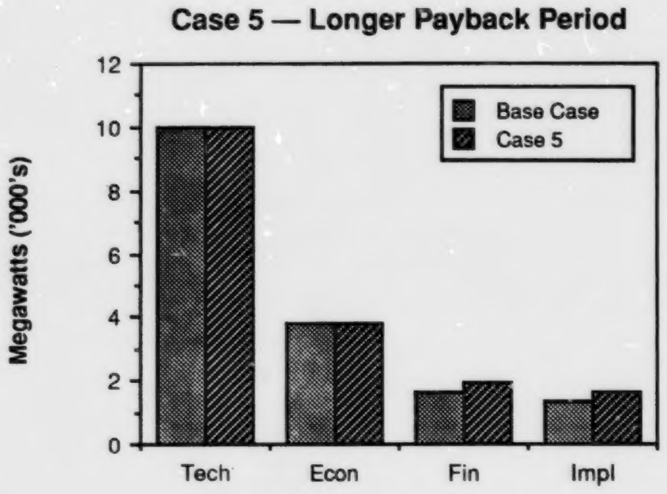

Figure 7.5
COGENERATION POTENTIAL IN ONTARIO

CASE 5 — LONGER PAYBACK PERIODS

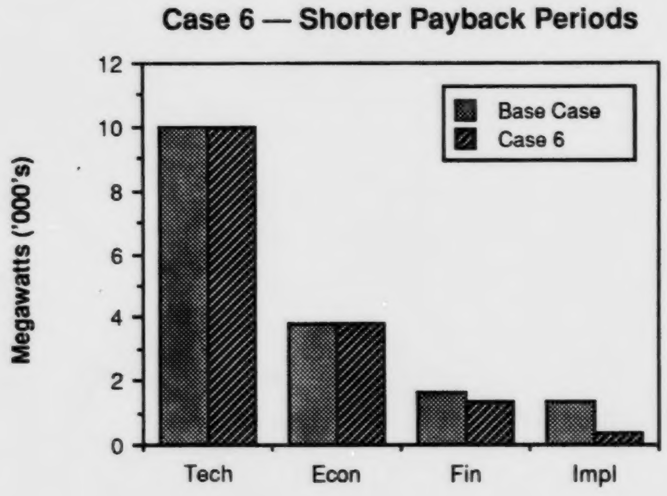

Figure 7.6
COGENERATION POTENTIAL IN ONTARIO

CASE 6 — SHORTER PAYBACK PERIODS

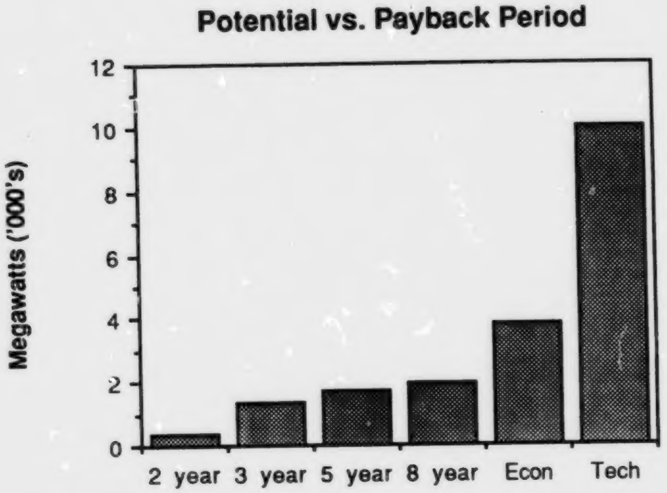

Figure 7.7
COGENERATION POTENTIAL IN ONTARIO

POTENTIAL vs. PAYBACK PERIOD

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BIBLIOGRAPHY

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APPENDIX A

LITERATURE REVIEW OF COGENERATION POTENTIAL

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LITERATURE REVIEW OF COGENERATION POTENTIAL

Leighton and Kidd Ltd. Report on Industrial By-Product Power. May 1977

This report and its associated survey were commissioned by the Royal Commission on Electric Power Planning (RCEPP) - The Porter Commission. A survey of all 268 industrial boiler plants with steam flows upwards of 40 000 lbs per hour was conducted. The study estimated that, including about 500 MW of installed industrial cogeneration capacity, the maximum technical potential, for by-product power was 3000 MW in 1977, increasing to 4000 MW by 1985. It stated that physical, economic and institutional constraints would preclude realization of the maximum potential. The report suggested that a joint program by industry, Ontario Hydro and the Province should be fashioned to accelerate development. A possible implementation target for such a program would be the installation of an additional 1500 MW to bring total installed capacity in industrial plants up to about 2000 MW by 1985.

Ontario Hydro Response to Leighton and Kidd Study

The Ontario Hydro review of the Leighton and Kidd estimates produced a target for 1985 of about 1200 MW of additional capacity, compared to the Leighton and Kidd target estimate of about 1500 MW. In a subsequent December 1978 study, Ontario Hydro estimated the additional potential by the year 2000 to be 2800 MW.* It is not clear what type of potential this figure represents - most likely it denotes a maximum technical potential.

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* Hydro estimates quoted in a 1982 internal Ministry of Energy memorandum.

Acres Shawinigan Limited Study of the Potential for Cogeneration in Canada - Industrial Steam Turbines, for Energy Mines and Resources Canada. December 1979

This survey and study focused on cogeneration based on boilers equipped with back-pressure steam turbines. Lowest size considered was 100 000 or more pounds per hour of steam. A 100 000 lb/h process would typically accommodate an electricity generator of 4000 kW capacity. Survey responses were received from 202 out of a possible total of 344 Canadian plants with steam demands in excess of 100 000 lb; in Ontario, there were 62 respondents.

For the Province of Ontario, a total unexploited technical potential of 1447 MW was estimated. However, fluctuating process steam loads, low temperature waste materials, mechanical-device turbines and environmental considerations combine to place the estimate of realizable unexploited technical potential in the order of two-thirds of total potential (or about 1000 MW for Ontario). Of the realizable technical potential, about two-thirds were estimated as economical (or about 650 MW for Ontario), and about 375 MW as financially feasible from the investor's point of view.

Royal Commission on Electric Power Planning. Volume 1 - Concepts, Conclusions and Recommendations. February 1980

The Commission concluded that the maximum potential for retrofitted and new industrial cogeneration projects could represent as much as 2300 MW of additional electric generating capacity in Ontario by the end of the century under assumed conditions. One of the conditions was that cogeneration facilities would be fueled mostly by natural gas in the 1980s and early 1990s, and coal thereafter. Financially feasible projects were estimated to provide 400 MW of capacity by the year 2000.

Industrial Cogeneration in Ontario. Cogeneration Associates Ltd., for Ontario Ministry of Energy. October 1980

The technical potential for additional industrial cogeneration by 1990 was estimated at more than 4600 MW of electrical power. Gas turbines represented the dominant technology (92% of total capacity) with steam turbines suggested for only biomass-based projects in the paper industry. The development of 1800 MW of industrial cogenerated power by 1990 was expected to be financially feasible given investment grants of about 30% and maximum acceptable payback periods of 5 years.

The Potential for Economic Contribution of Industrial Cogeneration to the Ontario Bulk Electricity System. Ontario Hydro Report ERP-8114 and ECD 81-3. November 1981

The study estimated that some 400 MW of industrial cogeneration could be economically implemented by the year 2000, assuming no growth in industrial steam demand and assuming comparative nuclear cost 25% higher than forecasted. In addition, it indicated 180 MW of °practical' potential in municipal solid waste of which only 50 MW were expected to be implemented.

The total technical potential for industrial cogeneration was estimated to be about 3300 MW. The study pointed to back-pressure steam turbines as the most promising technology.

An Economic Update of the Potential for Cogeneration in Canada. Acres Consulting Services, for Energy, Mines and Resources Canada. August 1982

The study indicated that 15% and 70% of technically feasible projects could meet criteria of financial and economic viability, respectively. The greatest financial potential was found in the iron and steel and forest industries. In all industries, the potentials declined relative to the 1979 study. The 1979 economic and financial potentials of about 650 and 375 MW declined to about 575 and 140 MW respectively for industrial steam processes in excess of 100 000 lb/h. The declines stemmed from modified assumptions, including the use of natural gas rather than coal as incremental fuel, downward revisions in the forecast prices of electricity and more stringent investment criteria than those used in the 1979 study.

Diener, S.G. and S. Dupont
An Assessment of the Competitiveness
of Selected Energy Conservation and
Alternative Energy Technologies,
for the Economic Council of Canada, 1984

This study was an input to the Economic Council's study of low-cost energy futures for Canada. The authors relied on the Council's forecasts of the shadow and market prices of fuels and electricity and the technical data base of an earlier study (Acres Shawinigan, 1979). The study estimated the economic and financial potentials by the year 2000 for large industrial cogeneration in Ontario at 1125 and 385 MW, respectively. The base case analysis used a 7% real discount rate; at a 10% discount rate, the estimated economic potential was 25% higher.* The financial analysis used 5 years as the maximum acceptable payback period. The substantial increase in financial and economic potentials relative to the earlier Acres study of 1982 is a result of increases and decreases in the prices of electricity and fuels, respectively.

Energy 2000 - The Shape of
Ontario's Future Energy Demand
Ministry of Energy
September 1985

The report indicated that there is economic potential for additional industrial cogeneration of some 500 to 1000 MW, equivalent to 2 to 4% of Ontario Hydro's present capacity. (Technical potential was estimated to be about 5000 MW.) For the base outlook, it assumed that roughly 300 MW of new industrial cogeneration (for all size categories of industry) would be implemented by the year 2000.

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* This result stems from the fact that at higher discount rates the supply price of electricity from conventional bulk generation rises more than that associated with cogenerated electricity.

Meeting Future Energy Needs - An Initial Review of the Options. Ontario Hydro System Planning Division. November 1985

The report describes the results of studies which attempt to compare the economics of a wide variety of electricity supply options. The measure chosen for the comparisons is the 'Standard Cost'. The report estimated that at a standard cost of $52/MW.h (1984$) the cost of gas-fueled cogeneration is higher than hydraulic, nuclear or the more economic coal options. A waste-fueled plant has a standard cost of $32/MW.h which is cost-competitive with any supply or demand option. (The cost comparisons are based on a 4% real discount rate.) The report estimated that 150 to 1000 MW of industrial cogeneration could be developed by the year 2000. This estimate includes both waste- and gas-fueled plants. The report does not indicate the type of potential represented by the range - it is likely to be financial and/or implementation potential.

Ontario Hydro Annual Report for 1985. April 1986

The potential contribution of cogeneration to power requirements by the year 2000 is estimated to be a reasonably assured 150 MW and a less assured additional 850 MW. This appears to be a restatement of the numbers in Meeting Future Energy Needs (1985) and offers no clarification of the type of potential being estimated.

Select Committee on Energy, Toward a Balanced Electricity System, July 1986

The Committee reported that Ontario Hydro points to 340 MW of industrial cogeneration to come on stream by 2000. At the same time, Ontario Hydro is quoted as saying that they believe that with incentives and development programs, this number could be as high as 1400 MW The report also refers to Ministry of Energy estimates of 5000 MW of technical potential for additional industrial cogeneration. Up to 1000 MW could be brought into service by 2000 if the capacity were needed and if incentives were offered. The report also states that the

Ministry has estimated that without incentives 300 MW of cogeneration could be installed by the year 2000.

APPENDIX B

CASE STUDY DETAILS

APPENDIX B

TABLE B.1

Sector: Industrial
Subsector: Miscellaneous
Category: Low Heat Demand

Study Parameters

Existing Plant	- annual energy consumption	5.6 GW.h
	- in-house generating capacity	0.0 GW.h
Cogeneration	- potential cogeneration capacity	50 kW
	- potential cogeneration energy	0.438 GW.h
	- incremental capital cost	$125,000
	- incremental fuel consumption	2.7 x 10^9 Btu
	- incremental operation and maintenance cost	$1,000

Energy Use Profile

Month	Steam (000 pph)	Electric (000 kW.h)
Jan	7.608	394
Feb	7.608	423
Mar	7.608	330
Apr	7.608	413
May	7.608	458
Jun	7.608	532
Jul	7.608	580
Aug	7.608	610
Sep	7.608	480
Oct	7.608	450
Nov	7.608	450
Dec	7.608	450

Total Annual Steam Consumption: 66.6 M pounds

Total Annual Fuel Consumption: 7.75 x 1010 Btu

Details of Existing Power Plants

2 x 250 hp Volcano Boiler 15 psig

1 x 50 hp Volcano Boiler 15 psig

Boilers provide steam for emptying bottles, hot water washing, sterilizing and domestic hot water.

Cogeneration Mode Selected

Since the plant has a daily cyclic but steady demand steam load, a back-pressure steam turbine in conjunction with a new 120 psig boiler was selected.

Criteria for Selection

- Since the bottling plant uses a continuous steam supply, a small steam turbine was considered appropriate.
- Firm required a low maintenance installation.
- Electric loading was not a problem.
- Firm's existing boilers required replacement.

TABLE B.2

Sector: Industrial
Subsector: Miscellaneous
Category: Medium Heat Category

Study Parameters

Existing Plant	- annual energy consumption	4.7 GW.h
	- in-house generating capacity	0.0 GW.h
Cogeneration	- potential cogeneration capacity	3.0 MW
	- potential cogeneration energy	25.5 GW.h
	- incremental capital cost	$1,430,000
	- incremental fuel consumption	57.8×10^9 Btu
	- incremental operation and maintenance cost	$63,750

Energy Use Profile

Month	Steam (000 pph)	Electric (000 kW.h)
Jan	20	296
Feb	20	287
Mar	20	264
Apr	20	301
May	20	343
Jun	20	280
Jul	20	267
Aug	100	607
Sep	100	722
Oct	20	420
Nov	20	346
Dec	20	278

Total Annual Steam Consumption: 80.0 M pounds

Total Annual Fuel Consumption: 2 791 000 m^3 + 6 000 000 m^3 for storage area heating.

Details of Existing Power Plants

Boilers - gas fired 120 psig

1 x 35 000 pph B&W
1 x 45 000 pph B&W
1 x 30 000 pph FW

Cogeneration Mode Selected

Mode selected is a 3.0 MW gas turbine with a waste heat steam generator for base load operation. The plant uses 2.0 MW during daytime operation dropping to 0.7 MW in the offshift. The remainder of the capacity is used to generate electricity for sale. The boiler selected produces 20 000 pph to be used for process and plant heating (120 psig).

Criteria For Selection

- Provides sufficient electrical energy to cover all offseason demand with surplus available for sale to Ontario Hydro.

- Provides sufficient steam to suply process and plant heating needs during the offseason.

- Retain the exisitng 30 000 and 45 000 pph boilers to meet seasonal loads.

TABLE B.3

Sector: Insitutional
Subsector: University
Category: Medium Heat Demand

Study Parameters

Existing Plant	- annual energy consumption	37 GW.h
	- in-house generating capacity	10.366 GW.h 1.6 MW
Cogeneration	- potential cogeneration capacity	1.6 MW
	- potential cogeneration energy	10.366 GW.h
	- incremental capital cost	$733,700
	- incremental fuel consumption	70.0 x 109 Btu
	- incremental operation and maintenance cost	$23,000

Energy Use Profile

Month	**Steam** (000 pph)	**Electric** (000 kW.h)
Jan		
Feb		
Mar		
Apr		
May		
Jun	(60 average)	(4.2 MW average)
Jul		(6.5 MW peak)
Aug		
Sep		
Oct		
Nov		
Dec		

Total Annual Steam Consumption:

Total Annual Fuel Consumption: 5.8 million m3

Details of Existing Power Plants

2 x 100 000 pph Vickers dual-fired (gas/oil) boiler uprated from 150 psig to 300 psig.

1 operating - 1 standby

Cogeneration Mode Selected

1 x 1 MW Westinghouse back-pressure turbine sized to 60% of average steam load.

1 x 600 kW diesel generator.

Criteria For Selection

Steam turbine selected to operate base loaded for seven months of year. To reduce electricity charges.

Diesel Generator selected to reduce electricity charges, base load operation and to allow shutdown of boilers during summer months.

TABLE B.4

Sector: Institutional
Subsector: University
Category: High Heat Demand

Study Parameters

Existing Plant	- annual energy consumption	77 GW.h
	- in-house generating capacity (standby units)	0.8 GW.h
Cogeneration	- potential cogeneration capacity	3.0 MW
	- potential cogeneration energy	26 GW.h
	- incremental capital cost	$1,875,000
	- incremental fuel consumption	101.0 x 109 Btu
	- incremental operation and maintenance cost	$48,000

Energy Use Profile

Month	Steam (000 pph)	Electric (000 kW.h)
Jan	160	10 500
Feb	169 (actual)	10 500
Mar	158	10 500
Apr	101	10 500
May	75	11 000
Jun	50	13 000
Jul	25.5	14 500
Aug	25.5 (actual)	14 500 (actual)
Sep	50	13 000
Oct	75	11 500
Nov	100	11 000
Dec	140	10 500

Total Annual Steam Consumption:

Total Annual Fuel Consumption: 17 670 000 m3
natural gas

Details of Existing Power Plants

Boilers	1 x 50 000 pph 150 psig B&W
	1 x 70 000 pph 150 psig B&W
	1 x 100 000 pph 150 psig B&W
	1 x 150 000 pph 150 psig Vickers
Chillers	2 x 2 000 tons/hr Carrier centrifugal
	1 x 2 000 tons/hr Trane centrifugal
	1 x 500 tons/hr Carrier centrifugal
Diesels	2 x 1 000 kW oil-fired Crossley

Cogeneration Mode Selected

3 x 1 000 kW diesel generator.

Criteria For Selection

- Diesel selection based on electric power requirement falling in summer months when steam load is lowest.
- Need to replace existing emergency generator sets, if synchronous generators are still serviceable, further cost savings may be achieved.
- Ease of installation.
- Ease of tie-ins.
- Plans by region to supply steam from adjacent refuse burning site thereby allowing decommissioning of existing boilers. (Either some or all.)

TABLE B.5

Sector: Institutional
Subsector: Hospital
Category: Medium Heat Demand

Study Parameters

Existing Plant	- annual energy consumption	24.5 GW.h
	- in-house generating capacity	0.0 GW.h
Cogeneration	- potential cogeneration capacity	2.0 MW
	- potential cogeneration energy	17.5 GW.h
	- incremental capital cost	$990,000
	- incremental fuel consumption	101.0×10^9 Btu
	- incremental operation and maintenance cost	$141,480

Energy Use Profile

Month	**Steam** (000 pph)	**Electric** (000 kW.h)
Jan	29 (estimate)	1766
Feb	32.0 (actual)	1766
Mar	27 (estimate)	1766
Apr	20 (estimate)	2546
May	14 (estimate)	2864
Jun	10 (estimate)	3501
Jul	10 (estimate)	3501
Aug	10.764 (actual)	3501
Sep	10 (estimate)	3501
Oct	14 (estimate)	2864
Nov	20 (estimate)	1766
Dec	29 (estimate)	1766

Total Annual Steam Consumption:

Total Annual Fuel Consumption: Gas - 5.95 million m^3
Oil No. 2 - 81.828 L

Details of Existing Power Plants

Boilers	3 x 60 000 pph 125 psig natural gas
Chillers	3 x 1200 ton centrifugal elec.
Diesels	2 x 800 kW/4 160 volts (main hospital and O.R. emergency)
	1 x 400 kW/208 volts (O.R. back up)
	1 x 400 kW/550 volts (power plant back up)

Cogeneration Mode Selected

2 x 1000 kW diesels for base load.

Criteria For Selection

- Minimal summer steam demand coupled with peak summer electrical demand for air conditioning.
- Requirement for year-round hot water for laundry, kitchen and wash up.

TABLE B.6

Sector: Commercial
Subsector: Shopping Mall
Category: Medium Heat Demand

Study Parameters

Floor Space	- 500 000 ft2	
Existing Plant	- annual energy consumption	12.27 GW.h
	- in-house generating capacity	0.0 GW.h
Cogeneration	- potential cogeneration capacity	3.0 MW
	- potential cogeneration energy	14.76 GW.h
	- incremental capital cost	$876,500
	- incremental fuel consumption	204.0 x 109 Btu
	- incremental operation and maintenance cost	$108,000

Energy Use Profile

Month	**Steam** (000 pph)	**Electric** (000 kW.h)
Jan	0	1 260
Feb	0	1 248
Mar	0	1 260
Apr	0	1 300
May	0	1 350
Jun	0	1 400
Jul	0	1 545
Aug	0	1 600
Sep	0	1 500
Oct	0	1 400
Nov	0	1 300
Dec	0	1 260

Total Annual Steam Consumption: 0

Total Annual Fuel Consumption:

Details of Existing Power Plants

2000 tons of conventional Chillers.

Cogeneration Mode Selected

3000-kW gas turbine, waste-heat boiler plus 1 300 tons of absorption Chillers.

Criteria For Selection

The gas turbine and diesel generator are somewhat evenly matched at 3.0 MW. For less than a 3-year payback, the GT is favored, providing there are no unscheduled outages. Beyond 3 years, the diesel is favored.

The gas turbine offers a significantly better absorption cooling capacity than does the diesel.

TABLE B.7

Sector: Commercial
Subsector: Offices
Category: Medium Heat Demand

Study Parameters

Floor Space	- 500 000 ft2	
Existing Plant	- annual energy consumption	9.525 GW.h
	- in-house generating capacity	0.0 GW.h
Cogeneration	- potential cogeneration capacity	3.0 MW
	- potential cogeneration energy	7.77 GW.h
	- incremental capital cost	$1,360,000
	- incremental fuel consumption	33.3 x 109 Btu
	- incremental operation and maintenance cost	$70,000

Energy Use Profile

Month	**Steam** (000 pph)	**Electric** (000 kW.h - estimated)
Jan	0	700
Feb	0	680
Mar	0	700
Apr	0	750
May	0	800
Jun	0	900
Jul	0	1070
Aug	0	1100
Sep	0	1070
Oct	0	900
Nov	0	780
Dec	0	700

Total Annual Steam Consumption: 0

Total Annual Fuel Consumption: 8.64 x 1012 Btu/yr

Details of Existing Power Plants

2500 tons of centrifugal coolers.

Cogeneration Mode Selected

3 x 1000-kW gas-fired diesel generators.

Criteria For Selection

Cyclic daily demand and requirements for both part load and system redundancy (ability to operate with one unit out).

TABLE B.8

Sector: Residential
Subsector: Multiple Unit Apartment
Category: Low Heat Demand

Study Parameters

Building Size	- 250 units	
Existing Plant	- annual energy consumption	7.5 GW.h
	- in-house generating capacity	0.0 GW.h
Cogeneration	- potential cogeneration capacity	1.5 MW
	- potential cogeneration capacity	7.2 GW.h
	- incremental capital cost	$740,000
	- incremental fuel consumption	30.9 x 109 Btu
	- incremental operation and maintenance cost	$65,000

Energy Use Profile

Month	Steam (000 pph)	Electric (000 kW.h)
Jan	0	535
Feb	0	532
Mar	0	535
Apr	0	550
May	0	550
Jun	0	650
Jul	0	837
Aug	0	840
Sep	0	800
Oct	0	650
Nov	0	525
Dec	0	535

Total Annual Steam Consumption: 0

Total Annual Fuel Consumption: 5.88 x 1012 Btu/yr

Details of Existing Power Plants

1700 tons of centrifugal chillers.

Cogeneration Mode Selected

1 x 500-kW diesel generator.

1 x 1000-kW diesel generator.

Criteria For Selection

Due to size of electrical load, and daily cyclic variation, diesel units were selected.

APPENDIX C

PROJECT SPECIFIC RESULTS

PROJECT/CASE STUDY DETAILED RESULTS Base Case

	-- Updated Parameters --				-- Financial --		---- Cogeneration ----		
	Increm	Increm	Increm	Economic				Potential	
Seq.	Capital Cost (Base$k)	O/M Cost (Base$k)	Fuel Cons. (TJ)	Supply Price ($/MWh)	Pay Back* (yrs)	Equity Return* (%)	Econ (kW)	Fin (kW)	Impl (kW)
1	8329.7	310.6	777.5	10.89	1.8	224.9%	22034	22034	22034
2	9607.8	329.5	972.0	10.34	1.6	284.2%	29055	29055	29055
3	8000.0	305.7	602.9	11.60	2.0	167.7%	19276	19276	19276
4	7368.7	296.4	331.4	17.02	3.8	54.2%	9650	9650	0
5	6306.2	280.6	800.2	9.70	1.3	698.9%	22870	22870	22870
6	1879.5	215.0	95.7	22.07	4.5	41.1%	2720	2720	0
7	8888.6	318.9	416.5	16.15	3.4	63.7%	12562	12562	0
8	2697.6	227.2	132.2	20.02	4.1	47.2%	4235	4235	0
9	4407.4	252.5	256.2	15.14	2.9	83.5%	8926	8926	8926
10	3618.7	240.8	205.8	16.05	3.1	76.4%	6167	6167	0
11	4030.0	246.9	305.0	13.55	2.3	125.9%	10079	10079	10079
12	2949.0	230.9	212.8	14.97	2.5	105.7%	6248	6248	6248
13	5189.5	264.1	429.0	12.26	2.0	174.1%	14905	14905	14905
14	3217.0	234.9	278.9	13.12	1.9	187.1%	8405	8405	8405
15	2483.4	224.0	137.5	18.36	3.5	61.7%	4142	4142	0
16	2864.5	229.6	55.0	43.94	11.0	0.0%	2313	0	0
17	2642.0	226.3	168.3	26.00	4.8	35.3%	5313	5313	0
18	3468.0	238.6	205.1	25.05	4.6	38.4%	8613	8613	0
19	6996.3	290.8	69.1	59.55	11.0	0.0%	0	0	0
20	2889.8	230.0	73.4	36.86	11.0	0.0%	5128	0	0
21	5649.8	270.9	241.6	28.08	5.8	28.2%	16693	0	0
22	5773.4	272.7	467.7	21.87	3.1	73.3%	16803	16803	0
23	16448.8	430.9	1586.8	20.49	2.6	101.5%	46953	46953	46953
24	4980.1	261.0	249.7	26.06	5.4	29.5%	7858	0	0
25	3430.8	238.0	251.8	23.62	3.7	54.7%	7443	7443	0
26	4883.3	259.5	256.1	26.27	5.4	29.2%	7399	0	0
27	1403.1	208.0	96.7	26.82	4.8	34.6%	2893	2893	0
28	2164.9	219.3	70.3	35.19	11.0	0.0%	2683	0	0
29	12629.8	374.3	1353.9	20.63	2.3	130.7%	40819	40819	40819
30	8920.9	319.4	1224.6	19.85	1.9	196.6%	36683	36683	36683
31	4269.8	250.5	311.3	23.00	3.5	58.8%	9488	9488	0
32	4098.8	247.9	406.7	21.42	2.6	96.9%	12023	12023	12023
33	10597.8	344.2	1063.9	20.52	2.4	119.1%	31483	31483	31483
34	1163.0	204.4	81.8	27.81	4.7	36.9%	2418	2418	0
35	1982.4	216.6	72.9	32.66	11.0	0.0%	2179	0	0

PROJECT/CASE STUDY DETAILED RESULTS (Cont'd) Base Case

	-- Updated Parameters --				-- Financial --		---- Cogeneration Potential ----		
Seq.	Increm Capital Cost (Base$k)	Increm O/M Cost (Base$k)	Increm Fuel Cons. (TJ)	Economic Supply Price ($/MWh)	Pay Back* (yrs)	Equity Return* (%)	Econ (kW)	Fin (kW)	Impl (kW)
36	3449.8	238.3	275.9	23.55	3.5	58.6%	7213	7213	0
37	12249.8	368.7	1557.8	19.28	1.8	212.2%	48003	48003	48003
38	3153.2	233.9	191.1	25.95	4.9	34.1%	5745	5745	0
39	4520.8	254.2	403.5	21.88	2.9	80.9%	12403	12403	12403
40	3147.9	233.8	228.7	23.89	3.8	52.5%	6753	6753	0
41	17075.3	440.2	1549.1	20.76	2.7	96.5%	45843	45843	45843
42	2605.9	225.8	129.9	27.30	5.8	25.3%	3931	0	0
43	2475.6	223.9	254.3	22.62	2.8	86.6%	7483	7483	7483
44	2626.0	226.1	128.3	28.72	6.8	18.9%	5728	0	0
45	1526.4	209.8	37.0	41.72	11.0	0.0%	2152	0	0
46	2437.0	223.3	120.4	27.94	5.3	33.0%	3603	0	0
47	6179.8	278.8	87.2	43.68	11.0	0.0%	15315	0	0
48	2119.8	218.6	139.3	26.44	4.9	34.2%	4193	4193	0
49	2629.8	226.2	67.4	37.13	11.0	0.0%	3146	0	0
50	3648.4	241.3	48.1	52.69	11.0	0.0%	0	0	0
51	3453.9	238.4	199.0	26.17	5.1	31.8%	5743	0	0
52	2326.3	221.7	152.1	26.17	4.8	35.3%	5259	5259	0
53	1426.4	208.3	81.6	29.04	6.6	18.4%	2403	0	0
54	2831.8	229.2	290.7	21.84	2.6	97.3%	8593	8593	8593
55	1788.8	213.7	88.2	29.55	7.3	15.0%	2643	0	0
56	1650.9	211.7	42.2	40.50	11.0	0.0%	2803	0	0
57	125.0	1.0	2.8	35.80	11.0	0.0%	50	0	0
58	150.0	6.0	10.5	17.14	3.4	65.0%	200	200	0
59	125.0	1.0	2.8	53.51	11.0	0.0%	0	0	0
60	1430.0	63.8	61.0	15.81	2.3	125.9%	2000	2000	2000
61	773.7	23.0	73.8	37.43	11.0	0.0%	1600	0	0
62	1875.0	48.0	106.5	23.64	3.5	60.0%	3000	3000	0
63	990.0	141.5	106.5	37.72	11.0	0.0%	2000	0	0
64	876.5	108.0	215.2	72.14	11.0	0.0%	0	0	0
65	1360.0	70.0	35.1	41.26	11.0	0.0%	3000	0	0
66	740.0	65.0	32.6	35.82	11.0	0.0%	1500	0	0
	277998	15004	20979	26.88	5.6	70.3%			

* - Payback Period of 11.0 years and/or Equity Return of 0.0% indicates that the project is not feasible within its first ten years of operation.

SUMMARY BY REPORT GROUP

Base Case

Sector	Sub-Sector	Heat Demand Category	Report Group	Average Supply Price ($/MWh)	Average Payback Period (yrs)	----- Cogeneration Potential ----- Technical (kW)	Econ (kW)	Fin (kW)	Implem (kW)	Upgrade Factor	--------- Total Potential -------- Tech (MW)	Econ (MW)	Fin (MW)	Implem (MW)
Industry	- Pulp & Paper	Low	111	35.80	11.0	50	50	0	0	91	4.6	4.6	0.0	0.0
		Medium	112	17.14	3.4	200	200	200	0	41	8.2	8.2	8.2	0.0
		High	113	14.75	2.7	181274	181274	181274	141798	2.125	385.2	385.2	385.2	301.3
	- Iron & Steel	High	123	23.01	3.7	79045	79055	71198	46953	2.25	177.9	177.9	160.2	105.6
	- Smelting	High	133	24.96	4.3	11408	11413	7483	7483	5	57.0	57.1	37.4	37.4
	- Petroleum	High	143	22.55	3.3	125942	125958	125958	106248	1.83	230.5	230.5	230.5	194.4
	- Chemicals	High	153	24.61	4.3	145862	145885	135804	121006	1.8	262.6	262.6	244.4	217.8
	- All Other	Low	191	53.51	11.0	50	0	0	0	583	29.2	0.0	0.0	0.0
		Medium	192	15.81	2.3	2000	2000	2000	2000	230	460.0	460.0	460.0	460.0
		High	193	34.19	7.9	115618	101813	31969	8593	3.5	404.7	356.3	111.9	30.1
Institutional	- Universites	Medium	212	37.43	11.0	1600	1600	0	0	9	14.4	14.4	0.0	0.0
		High	213	23.64	3.5	3000	3000	3000	0	6	18.0	18.0	18.0	0.0
	- Hospitals	Medium	222	37.72	11.0	2000	2000	0	0	39	78.0	78.0	0.0	0.0
Commercial	- Large Malls	Medium	312	72.14	11.0	3000	0	0	0	101	303.0	0.0	0.0	0.0
	- Offices	Medium	322	41.26	11.0	3000	3000	0	0	153	459.0	459.0	0.0	0.0
Residential	- Apartments	Low	411	35.82	11.0	1500	1500	0	0	881	1321.5	1321.5	0.0	0.0
											4213.6	3833.2	1655.9	1346.7

PROJECT/CASE STUDY DETAILED RESULTS

Case 1 - Lower Energy Price

Seq.	-- Updated Parameters -- Increm Capital Cost (Base$k)	Increm O/M Cost (Base$k)	Increm Fuel Cons. (TJ)	Economic Supply Price ($/MWh)	-- Financial -- Pay Back* (yrs)	Equity Return* (%)	---- Cogeneration ---- Potential Econ (kW)	Fin (kW)	Impl (kW)
1	8329.7	310.6	777.5	11.04	1.7	262.5%	22034	22034	22034
2	9607.8	329.5	972.0	10.49	1.5	[illegible]2.1%	29055	29055	29055
3	8000.0	305.7	602.9	11.74	2.0	178.0%	19276	19276	19276
4	7368.7	296.4	331.4	17.16	3.6	57.6%	9650	9650	0
5	6306.2	280.6	800.2	9.85	1.2	**	22870	22870	22870
6	1879.5	215.0	95.7	22.21	4.2	45.8%	2720	2720	0
7	8888.6	318.9	416.5	16.29	3.4	63.5%	12562	12562	0
8	2697.6	227.2	132.2	20.16	3.9	51.4%	4235	4235	0
9	4407.4	252.5	256.2	15.28	2.7	91.2%	8926	8926	8926
10	3618.7	240.8	205.8	16.18	2.9	83.6%	6167	6167	6167
11	4030.0	246.9	305.0	13.69	2.2	141.0%	10079	10079	10079
12	2949.0	230.9	212.8	15.12	2.4	118.1%	6248	6248	6248
13	5189.5	264.1	429.0	12.40	1.9	183.0%	14905	14905	14905
14	3217.0	234.9	278.9	13.27	1.9	183.8%	8405	8405	8405
15	2483.4	224.0	137.5	18.50	3.3	67.9%	4142	4142	0
16	2864.5	229.6	55.0	44.30	11.0	0.0%	2313	0	0
17	2642.0	226.3	168.3	26.41	4.3	42.5%	5313	5313	0
18	3468.0	238.6	205.1	25.45	4.1	45.0%	8613	8613	0
19	6996.3	290.8	69.1	59.93	11.0	0.0%	0	0	0
20	2889.8	230.0	73.4	37.23	11.0	0.0%	5128	0	0
21	5649.8	270.9	241.6	28.49	6.3	24.4%	16693	0	0
22	5773.4	272.7	467.7	22.28	2.8	87.1%	16803	16803	16803
23	16448.8	430.9	1586.8	20.91	2.3	123.3%	46953	46953	46953
24	4980.1	261.0	249.7	26.47	4.9	33.9%	7858	7858	0
25	3430.8	238.0	251.8	24.03	3.3	64.9%	7443	7443	0
26	4883.3	259.5	256.1	26.68	4.9	33.8%	7399	7399	0
27	1403.1	208.0	96.7	27.20	4.1	44.5%	2893	2893	0
28	2164.9	219.3	70.3	35.57	11.0	0.0%	2683	0	0
29	12629.8	374.3	1353.9	21.06	2.2	138.4%	40819	40819	40819
30	8920.9	319.4	1224.6	20.28	1.7	242.1%	36683	36683	36683
31	4269.8	250.5	311.3	23.40	3.2	68.9%	9488	9488	0
32	4098.8	247.9	406.7	21.83	2.4	119.7%	12023	12023	12023
33	10597.8	344.2	1063.9	20.94	2.3	131.1%	31483	31483	31483
34	1163.0	204.4	81.8	28.18	4.5	39.8%	2418	2418	0
35	1982.4	216.6	72.9	33.03	9.6	12.0%	2179	0	0

PROJECT/CASE STUDY DETAILED RESULTS (Cont'd) Case 1 - Lower Energy Price

	-- Updated Parameters --				-- Financial --		---- Cogeneration ----		
	Increm Capital	Increm O/M	Increm Fuel	Economic Supply	Pay	Equity		Potential	
Seq.	Cost (Base$k)	Cost (Base$k)	Cons. (TJ)	Price ($/MWh)	Back* (yrs)	Return* (%)	Econ (kW)	Fin (kW)	Impl (kW)
36	3449.8	238.3	275.9	23.96	3.2	70.3%	7213	7213	0
37	12249.8	368.7	1557.8	19.69	1.7	238.5%	48003	48003	48003
38	3153.2	233.9	191.1	26.36	4.4	40.4%	5745	5745	0
39	4520.8	254.2	403.5	22.29	2.6	97.9%	12403	12403	12403
40	3147.9	233.8	228.7	24.30	3.4	62.6%	6753	6753	0
41	17075.3	440.2	1549.1	21.18	2.5	109.7%	45843	45843	45843
42	2605.9	225.8	129.9	27.68	5.2	30.7%	3931	0	0
43	2475.6	223.9	254.3	23.04	2.5	108.7%	7483	7483	7483
44	2626.0	226.1	128.3	29.12	6.0	24.5%	5728	0	0
45	1526.4	209.8	37.0	42.05	11.0	0.0%	2152	0	0
46	2437.0	223.3	120.4	28.32	5.6	28.6%	3603	0	0
47	6179.8	278.8	87.2	44.02	11.0	0.0%	15315	0	0
48	2119.8	218.6	139.3	26.84	4.3	42.0%	4193	4193	0
49	2629.8	226.2	67.4	37.49	11.0	0.0%	3146	0	0
50	3648.4	241.3	48.1	53.04	11.0	0.0%	0	0	0
51	3453.9	238.4	199.0	26.58	4.6	37.5%	5743	5743	0
52	2326.3	221.7	152.1	26.58	4.2	43.0%	5259	5259	0
53	1426.4	208.3	81.6	29.42	5.6	27.4%	2403	0	0
54	2831.8	229.2	290.7	22.24	2.3	121.7%	8593	8593	8593
55	1788.8	213.7	88.2	29.92	6.3	22.7%	2643	0	0
56	1650.9	211.7	42.2	40.84	11.0	0.0%	2803	0	0
57	125.0	1.0	2.8	36.03	11.0	0.0%	50	0	0
58	150.0	6.0	10.5	17.33	3.2	68.6%	200	200	0
59	125.0	1.0	2.8	54.21	11.0	0.0%	0	0	0
60	1430.0	63.8	61.0	16.04	2.3	126.4%	2000	2000	2000
61	773.7	23.0	73.8	39.36	5.8	24.8%	1600	0	0
62	1875.0	48.0	106.5	24.71	2.6	103.0%	3000	3000	3000
63	990.0	141.5	106.5	39.37	5.0	30.4%	2000	0	0
64	876.5	108.0	215.2	76.08	11.0	0.0%	0	0	0
65	1360.0	70.0	35.1	42.48	9.9	11.8%	3000	0	0
66	740.0	65.0	32.6	37.04	5.9	25.6%	1500	0	0
	277998	15004	20979	27.34	5.0	66.9%			

* - Payback Period of 11.0 years and/or Equity Return of 0.0% indicates that the project is not feasible within its first ten years of operation.

** - Return on Equity exceeds 800%

SUMMARY BY REPORT GROUP

Case 1 - Lower Energy Prices

						----- Cogeneration Potential -----					--------- Total Potential --------			
Sector	Sub-Sector	Heat Demand Category	Report Group	Average Supply Price ($/MWh)	Average Payback Period (yrs)	Technical (kW)	Econ (kW)	Fin (kW)	Implem (kW)	Upgrade Factor	Tech (MW)	Econ (MW)	Fin. (MW)	Implem (MW)
Industry	- Pulp & Paper	Low	111	36.03	11.0	50	50	0	0	91	4.6	4.6	0.0	0.0
		Medium	112	17.33	3.2	200	200	200	0	41	8.2	8.2	8.2	0.0
		High	113	14.89	2.6	181274	181274	181274	147965	2.125	385.2	385.2	385.2	314.4
	- Iron & Steel	High	123	23.42	3.3	79045	79055	79055	63755	2.25	177.9	177.9	177.9	143.4
	- Smelting	High	133	25.36	3.9	11408	11413	7483	7483	5	57.0	57.1	37.4	37.4
	- Petroleum	High	143	22.96	3.0	125942	125958	125958	106248	1.83	230.5	230.5	230.5	194.4
	- Chemicals	High	153	25.02	4.0	145862	145885	143203	121006	1.8	262.6	262.6	257.8	217.8
	- All Other	Low	191	54.21	11.0	50	0	0	0	583	29.2	0.0	0.0	0.0
		Medium	192	16.04	2.3	2000	2000	2000	2000	230	460.0	460.0	460.0	460.0
		High	193	34.57	7.6	115618	101813	37712	8593	3.5	404.7	356.3	132.0	30.1
Institutional	- Universites	Medium	212	39.36	5.8	1600	1600	0	0	9	14.4	14.4	0.0	0.0
		High	213	24.71	2.6	3000	3000	3000	3000	6	18.0	18.0	18.0	18.0
	- Hospitals	Medium	222	39.37	5.0	2000	2000	0	0	39	78.0	78.0	0.0	0.0
Commercial	- Large Malls	Medium	312	76.08	11.0	3000	0	0	0	101	303.0	0.0	0.0	0.0
	- Offices	Medium	322	42.48	9.9	3000	3000	0	0	153	459.0	459.0	0.0	0.0
Residential	- Apartments	Low	411	37.04	5.9	1500	1500	0	0	881	1321.5	1321.5	0.0	0.0
											4213.6	3833.2	1707.0	1415.6

PROJECT/CASE STUDY DETAILED RESULTS | Case 2 - High Electricity Prices

	-- Updated Parameters --				-- Financial --		---- Cogeneration Potential ----		
Seq.	Increm Capital Cost (Base$k)	Increm O/M Cost (Base$k)	Increm Fuel Cons. (TJ)	Economic Supply Price ($/MWh)	Pay Back* (yrs)	Equity Return* (%)	Econ (kW)	Fin (kW)	Impl (kW)
1	8329.7	310.6	777.5	10.89	0.7	0.0%	22034	22034	22034
2	9607.8	329.5	972.0	10.34	0.6	**	29055	29055	29055
3	8000.0	305.7	602.9	11.60	1.1	0.0%	19276	19276	19276
4	7368.7	296.4	331.4	17.02	1.5	0.0%	9650	9650	9650
5	6306.2	280.6	800.2	9.70	0.6	**	22870	22870	22870
6	1879.5	215.0	95.7	22.07	1.4	443.6%	2720	2720	2720
7	8888.6	318.9	416.5	16.15	2.0	173.0%	12562	12562	12562
8	2697.6	227.2	132.2	20.02	1.4	447.3%	4235	4235	4235
9	4407.4	252.5	256.2	15.14	1.1	0.0%	8926	8926	8926
10	3618.7	240.8	205.8	16.05	1.1	0.0%	6167	6167	6167
11	4030.0	246.9	305.0	13.55	0.9	0.0%	10079	10079	10079
12	2949.0	230.9	212.8	14.97	0.9	0.0%	6248	6248	6248
13	5189.5	264.1	429.0	12.26	1.1	0.0%	14905	14905	14905
14	3217.0	234.9	278.9	13.12	1.9	187.1%	8405	8405	8405
15	2483.4	224.0	137.5	18.36	1.2	0.0%	4142	4142	4142
16	2864.5	229.6	55.0	43.94	4.0	52.7%	2313	2313	0
17	2642.0	226.3	168.3	26.00	1.2	0.0%	5313	5313	5313
18	3468.0	238.6	205.1	25.05	1.2	0.0%	8613	8613	8613
19	6996.3	290.8	69.1	59.55	7.9	20.1%	0	0	0
20	2889.8	230.0	73.4	36.86	11.0	0.0%	5128	0	0
21	5649.8	270.9	241.6	28.08	4.9	37.7%	16693	16693	0
22	5773.4	272.7	467.7	21.87	0.9	0.0%	16803	16803	16803
23	16448.8	430.9	1586.8	20.49	0.8	0.0%	46953	46953	46953
24	4980.1	261.0	249.7	26.06	1.5	0.0%	7858	7858	7858
25	3430.8	238.0	251.8	23.62	1.0	0.0%	7443	7443	7443
26	4883.3	259.5	256.1	26.27	1.4	432.2%	7399	7399	7399
27	1403.1	208.0	96.7	26.82	1.0	0.0%	2893	2893	2893
28	2164.9	219.3	70.3	35.19	2.4	124.1%	2683	2683	2683
29	12629.8	374.3	1353.9	20.63	1.5	360.9%	40819	40819	40819
30	8920.9	319.4	1224.6	19.85	0.8	0.0%	36683	36683	36683
31	4269.8	250.5	311.3	23.00	1.0	0.0%	9488	9488	9488
32	4098.8	247.9	406.7	21.42	0.7	0.0%	12023	12023	12023
33	10597.8	344.2	1063.9	20.52	1.2	0.0%	31483	31483	31483
34	1163.0	204.4	81.8	27.81	1.7	257.3%	2418	2418	2418
35	1982.4	216.6	72.9	32.66	2.0	174.7%	2179	2179	2179

PROJECT/CASE STUDY DETAILED RESULTS (Cont'd) Case 2 - High Electricity Prices

	-- Updated Parameters --				-- Financial --		---- Cogeneration ----		
	Increm	Increm	Increm	Economic				Potential	
Seq.	Capital Cost (Base$k)	O/M Cost (Base$k)	Fuel Cons. (TJ)	Supply Price ($/MWh)	Pay Back* (yrs)	Equity Return* (%)	Econ (kW)	Fin (kW)	Impl (kW)
36	3449.8	238.3	275.9	23.55	0.9	0.0%	7213	7213	7213
37	12249.8	368.7	1557.8	19.28	1.1	0.0%	48003	48003	48003
38	3153.2	233.9	191.1	25.95	1.2	0.0%	5745	5745	5745
39	4520.8	254.2	403.5	21.88	0.8	0.0%	12403	12403	12403
40	3147.9	233.8	228.7	23.89	1.0	0.0%	6753	6753	6753
41	17075.3	440.2	1549.1	20.76	1.0	0.0%	45843	45843	45843
42	2605.9	225.8	129.9	27.30	1.4	444.8%	3931	3931	3931
43	2475.6	223.9	254.3	22.62	0.7	0.0%	7483	7483	7483
44	2626.0	226.1	128.3	28.72	1.5	331.6%	5728	5728	5728
45	1526.4	209.8	37.0	41.72	3.1	79.2%	2152	2152	0
46	2437.0	223.3	120.4	27.94	5.3	33.0%	3603	0	0
47	6179.8	278.8	87.2	43.68	4.6	42.9%	15315	15315	0
48	2119.8	218.6	139.3	26.44	1.1	0.0%	4193	4193	4193
49	2629.8	226.2	67.4	37.13	2.9	88.9%	3146	3146	3146
50	3648.4	241.3	48.1	52.69	5.7	31.6%	0	0	0
51	3453.9	238.4	199.0	26.17	1.3	674.1%	5743	5743	5743
52	2326.3	221.7	152.1	26.17	1.2	0.0%	5259	5259	5259
53	1426.4	208.3	81.6	29.04	1.3	751.0%	2403	2403	2403
54	2831.8	229.2	290.7	21.84	0.7	0.0%	8593	8593	8593
55	1788.8	213.7	88.2	29.55	1.5	380.9%	2643	2643	2643
56	1650.9	211.7	42.2	40.50	3.0	84.3%	2803	2803	2803
57	125.0	1.0	2.8	35.80	4.5	42.5%	50	50	0
58	150.0	6.0	10.5	17.14	1.3	0.0%	200	200	200
59	125.0	1.0	2.8	53.51	6.0	28.8%	0	0	0
60	1430.0	63.8	61.0	15.81	1.8	224.5%	2000	2000	2000
61	773.7	23.0	73.8	37.43	1.4	477.2%	1600	1600	1600
62	1875.0	48.0	106.5	23.64	1.0	0.0%	3000	3000	3000
63	990.0	141.5	106.5	37.72	1.1	0.0%	2000	2000	2000
64	876.5	108.0	215.2	72.14	7.1	23.0%	0	0	0
65	1360.0	70.0	35.1	41.26	3.0	81.3%	3000	3000	0
66	740.0	65.0	32.6	35.82	1.8	214.8%	1500	1500	1500
	277998	15004	20979	26.88	2.1	93.7%			

* - Payback Period of 11.0 years and/or Equity Return of 0.0% indicates that the project is not feasible within its first ten years of operation.

** - Equity Return exceeds 800%

SUMMARY BY REPORT GROUP

Case 2 - High Electricity Prices

Sector	Sub-Sector	Heat Demand Category	Report Group	Average Supply Price ($/MWh)	Average Payback Period (yrs)	----- Cogeneration Potential ----- Technical (kW)	Econ (kW)	Fin (kW)	Implem (kW)	Upgrade Factor	--------- Total Potential -------- Tech (MW)	Econ (MW)	Fin (MW)	Implem (MW)
Industry	- Pulp & Paper	Low	111	35.80	4.5	50	50	50	0	91	4.6	4.6	4.6	0.0
		Medium	112	17.14	1.3	200	200	200	200	41	8.2	8.2	8.2	8.2
		High	113	14.75	1.2	181274	181274	181274	181274	2.125	385.2	385.2	385.2	385.2
	- Iron & Steel	High	123	23.01	1.0	79045	79055	79055	79055	2.25	177.9	177.9	177.9	177.9
	- Smelting	High	133	24.96	1.1	11408	11413	11413	11413	5	57.0	57.1	57.1	57.1
	- Petroleum	High	143	22.55	1.0	125942	125958	125958	125958	1.83	230.5	230.5	230.5	230.5
	- Chemicals	High	153	24.61	1.3	145862	145885	145885	145885	1.8	262.6	262.6	262.6	262.6
	- All Other	Low	191	53.51	6.0	50	0	0	0	583	29.2	0.0	0.0	0.0
		Medium	192	15.81	1.8	2000	2000	2000	2000	230	460.0	460.0	460.0	460.0
		High	193	34.19	3.3	115618	101813	93083	56611	3.5	404.7	356.3	325.8	198.1
Institutional	- Universites	Medium	212	37.43	1.4	1600	1600	1600	1600	9	14.4	14.4	14.4	14.4
		High	213	23.64	1.0	3000	3000	3000	3000	6	18.0	18.0	18.0	18.0
	- Hospitals	Medium	222	37.72	1.1	2000	2000	2000	2000	39	78.0	78.0	78.0	78.0
Commercial	- Large Malls	Medium	312	72.14	7.1	3000	0	0	0	101	303.0	0.0	0.0	0.0
	- Offices	Medium	322	41.26	3.0	3000	3000	3000	0	153	459.0	459.0	459.0	0.0
Residential	- Apartments	Low	411	35.82	1.8	1500	1500	1500	1500	881	1321.5	1321.5	1321.5	1321.5
											4213.6	3833.2	3802.7	3211.5

PROJECT/CASE STUDY DETAILED RESULTS   Case 3 - Higher Buyback Rate

	-- Updated Parameters --				-- Financial --		---- Cogeneration Potential ----		
Seq.	Increm Capital Cost (Base$k)	Increm O/M Cost (Base$k)	Increm Fuel Cons. (TJ)	Economic Supply Price ($/MWh)	Pay Back* (yrs)	Equity Return* (%)	Econ (kW)	Fin (kW)	Impl (kW)
1	8329.7	310.6	777.5	10.89	1.8	224.9%	22034	22034	22034
2	9607.8	329.5	972.0	10.34	1.6	284.2%	29055	29055	29055
3	8000.0	305.7	602.9	11.60	1.8	208.5%	19276	19276	19276
4	7368.7	296.4	331.4	17.02	3.8	54.2%	9650	9650	0
5	6306.2	280.6	800.2	9.70	1.2	**	22870	22870	22870
6	1879.5	215.0	95.7	22.07	4.5	41.1%	2720	2720	0
7	8888.6	318.9	416.5	16.15	3.1	77.5%	12562	12562	0
8	2697.6	227.2	132.2	20.02	4.1	47.2%	4235	4235	0
9	4407.4	252.5	256.2	15.14	2.9	83.5%	8926	8926	8926
10	3618.7	240.8	205.8	16.05	3.1	76.4%	6167	6167	0
11	4030.0	246.9	305.0	13.55	2.3	125.9%	10079	10079	10079
12	2949.0	230.9	212.8	14.97	2.5	105.7%	6248	6248	6248
13	5189.5	264.1	429.0	12.26	1.7	233.9%	14905	14905	14905
14	3217.0	234.9	278.9	13.12	1.5	347.3%	8405	8405	8405
15	2483.4	224.0	137.5	18.36	3.5	61.7%	4142	4142	0
16	2864.5	229.6	55.0	43.94	11.0	0.0%	2313	0	0
17	2642.0	226.3	168.3	26.00	4.8	35.3%	5313	5313	0
18	3468.0	238.6	205.1	25.05	4.6	38.4%	8613	8613	0
19	6996.3	290.8	69.1	59.55	11.0	0.0%	0	0	0
20	2889.8	230.0	73.4	36.86	7.4	20.4%	5128	0	0
21	5649.8	270.9	241.6	28.08	4.2	45.8%	16693	16693	0
22	5773.4	272.7	467.7	21.87	3.1	73.3%	16803	16803	0
23	16448.8	430.9	1586.8	20.49	2.6	101.5%	46953	46953	46953
24	4980.1	261.0	249.7	26.06	5.4	29.5%	7858	0	0
25	3430.8	238.0	251.8	23.62	3.7	54.7%	7443	7443	0
26	4883.3	259.5	256.1	26.27	5.4	29.2%	7399	0	0
27	1403.1	208.0	96.7	26.82	4.8	34.6%	2893	2893	0
28	2164.9	219.3	70.3	35.19	11.0	0.0%	2683	0	0
29	12629.8	374.3	1353.9	20.63	1.8	227.8%	40819	40819	40819
30	8920.9	319.4	1224.6	19.85	1.6	288.9%	36683	36683	36683
31	4269.8	250.5	311.3	23.00	3.5	59.9%	9488	9488	0
32	4098.8	247.9	406.7	21.42	2.6	96.9%	12023	12023	12023
33	10597.8	344.2	1063.9	20.52	2.0	173.3%	31483	31483	31483
34	1163.0	204.4	81.8	27.81	3.6	56.9%	2418	2418	0
35	1982.4	216.6	72.9	32.66	11.0	0.0%	2179	0	0

PROJECT/CASE STUDY DETAILED RESULTS (Cont'd) Case 3 - Higher Buyback Rate

	-- Updated Parameters --				-- Financial --		---- Cogeneration ----		
	Increm	Increm	Increm	Economic				Potential	
Seq.	Capital Cost (Base$k)	O/M Cost (Base$k)	Fuel Cons. (TJ)	Supply Price ($/MWh)	Pay Back* (yrs)	Equity Return* (%)	Econ (kW)	Fin (kW)	Impl (kW)
36	3449.8	238.3	275.9	23.55	3.5	58.6%	7213	7213	0
37	12249.8	368.7	1557.8	19.28	1.4	439.9%	48003	48003	48003
38	3153.2	233.9	191.1	25.95	4.9	34.1%	5745	5745	0
39	4520.8	254.2	403.5	21.88	2.9	80.9%	12403	12403	12403
40	3147.9	233.8	228.7	23.89	3.8	52.5%	6753	6753	0
41	17075.3	440.2	1549.1	20.76	2.4	115.9%	45843	45843	45843
42	2605.9	225.8	129.9	27.30	5.8	25.3%	3931	0	0
43	2475.6	223.9	254.3	22.62	2.8	86.6%	7483	7483	7483
44	2626.0	226.1	128.3	28.72	6.8	18.9%	5728	0	0
45	1536.4	209.8	37.0	41.72	11.0	0.0%	2152	0	0
46	2437.0	223.3	120.4	27.94	3.6	58.9%	3603	3603	0
47	6179.8	278.8	87.2	43.68	11.0	0.0%	15315	0	0
48	2119.8	218.6	139.3	26.44	4.9	34.2%	4193	4193	0
49	2629.8	226.2	67.4	37.13	11.0	0.0%	3146	0	0
50	3648.4	241.3	48.1	52.69	11.0	0.0%	0	0	0
51	3453.9	238.4	199.0	26.17	5.1	31.8%	5743	0	0
52	2326.3	221.7	152.1	26.17	4.8	35.3%	5259	5259	0
53	1426.4	208.3	81.6	29.04	6.6	18.4%	2403	0	0
54	2831.8	229.2	290.7	21.84	2.6	97.3%	8593	8593	8593
55	1788.8	213.7	88.2	29.55	7.3	15.0%	2643	0	0
56	1650.9	211.7	42.2	40.50	11.0	0.0%	2803	0	0
57	125.0	1.0	2.8	35.80	11.0	0.0%	50	0	0
58	150.0	6.0	10.5	17.14	3.4	65.0%	200	200	0
59	125.0	1.0	2.8	53.51	11.0	0.0%	0	0	0
60	1430.0	63.8	61.0	15.81	1.9	193.0%	2000	2000	2000
61	773.7	23.0	73.8	37.43	11.0	0.0%	1600	0	0
62	1875.0	48.0	106.5	23.64	3.5	60.0%	3000	3000	0
63	990.0	141.5	106.5	37.72	11.0	0.0%	2000	0	0
64	876.5	108.0	215.2	72.14	11.0	0.0%	0	0	0
65	1360.0	70.0	35.1	41.26	11.0	0.0%	3000	0	0
66	740.0	65.0	32.6	35.82	11.0	0.0%	1500	0	0
	277998	15004	20979	26.88	5.4	70.6%			

* - Payback Period of 11.0 years and/or Equity Return of 0.0% indicates that the project is not feasible within its first ten years of operation.

** - Equity Return exceeds 800%

SUMMARY BY REPORT GROUP

Case 3 - Higher Buyback Rate

Sector	Sub-Sector	Heat Demand Category	Report Group	Average Supply Price ($/MWh)	Average Payback Period (yrs)	----- Cogeneration Potential -----				Upgrade Factor	--------- Total Potential ---------			
						Technical (kW)	Econ (kW)	Fin (kW)	Implem (kW)		Tech (MW)	Econ (MW)	Fin (MW)	Implem (MW)
Industry	- Pulp & Paper	Low	111	35.80	11.0	50	50	0	0	91	4.6	4.6	0.0	0.0
		Medium	112	17.14	3.4	200	200	200	0	41	8.2	8.2	8.2	0.0
		High	113	14.75	2.6	181274	181274	181274	141798	2.125	385.2	385.2	385.2	301.3
	- Iron & Steel	High	123	23.01	3.7	79045	79055	71198	46953	2.25	177.9	177.9	160.2	105.6
	- Smelting	High	133	24.96	4.3	11408	11413	7483	7483	5	57.0	57.1	37.4	37.4
	- Petroleum	High	143	22.55	3.2	125942	125958	125958	106248	1.83	230.5	230.5	230.5	194.4
	- Chemicals	High	153	24.61	4.0	145862	145885	135804	121006	1.8	262.6	262.6	244.4	217.8
	- All Other	Low	191	53.51	11.0	50	0	0	0	583	29.2	0.0	0.0	0.0
		Medium	192	15.81	1.9	2000	2000	2000	2000	230	460.0	460.0	460.0	460.0
		High	193	34.19	7.5	115618	101813	52264	8593	3.5	404.7	356.3	182.9	30.1
Institutional	- Universites	Medium	212	37.43	11.0	1600	1600	0	0	9	14.4	14.4	0.0	0.0
		High	213	23.64	3.5	3000	3000	3000	0	6	18.0	18.0	18.0	0.0
	- Hospitals	Medium	222	37.72	11.0	2000	2000	0	0	39	78.0	78.0	0.0	0.0
Commercial	- Large Malls	Medium	312	72.14	11.0	3000	0	0	0	101	303.0	0.0	0.0	0.0
	- Offices	Medium	322	41.26	11.0	3000	3000	0	0	153	459.0	459.0	0.0	0.0
Residential	- Apartments	Low	411	35.82	11.0	1500	1500	0	0	881	1321.5	1321.5	0.0	0.0
											4213.6	3833.2	1726.9	1346.7

PROJECT/CASE STUDY DETAILED RESULTS

Case 4 - Investment Grants

	-- Updated Parameters --				-- Financial --		---- Cogeneration Potential ----		
Seq.	Increm Capital Cost (Base$k)	Increm O/M Cost (Base$k)	Increm Fuel Cons. (TJ)	Economic Supply Price ($/MWh)	Pay Back* (yrs)	Equity Return* (%)	Econ (kW)	Fin (kW)	Impl (kW)
1	8329.7	310.6	777.5	10.89	1.4	666.3%	22034	22034	22034
2	9607.8	329.5	972.0	10.34	1.3	**	29055	29055	29055
3	8000.0	305.7	602.9	11.60	1.6	398.4%	19276	19276	19276
4	7368.7	296.4	331.4	17.02	3.1	103.5%	9650	9650	0
5	6306.2	280.6	800.2	9.70	1.0	**	22870	22870	22870
6	1879.5	215.0	95.7	22.07	3.7	79.1%	2720	2720	0
7	8888.6	318.9	416.5	16.15	2.8	121.1%	12562	12562	12562
8	2697.6	227.2	132.2	20.02	3.4	90.5%	4235	4235	0
9	4407.4	252.5	256.2	15.14	2.4	163.1%	8926	8926	8926
10	3618.7	240.8	205.8	16.05	2.5	147.8%	6167	6167	6167
11	4030.0	246.9	305.0	13.55	1.9	266.7%	10079	10079	10079
12	2949.0	230.9	212.8	14.97	2.1	213.7%	6248	6248	6248
13	5189.5	264.1	429.0	12.26	1.6	422.8%	14905	14905	14905
14	3217.0	234.9	278.9	13.12	1.5	473.4%	8405	8405	8405
15	2483.4	224.0	137.5	18.36	2.8	118.3%	4142	4142	4142
16	2864.5	229.6	55.0	43.94	11.0	0.0%	2313	0	0
17	2642.0	226.3	168.3	26.00	3.9	70.4%	5313	5313	0
18	3468.0	238.6	205.1	25.05	3.7	75.7%	8613	8613	0
19	6996.3	290.8	69.1	59.55	11.0	0.0%	0	0	0
20	2889.8	230.0	73.4	36.86	9.9	17.9%	5128	0	0
21	5649.8	270.9	241.6	28.08	4.8	52.7%	16693	16693	0
22	5773.4	272.7	467.7	21.87	2.5	141.4%	16803	16803	16803
23	16448.8	430.9	1586.8	20.49	2.1	202.4%	46953	46953	46953
24	4980.1	261.0	249.7	26.06	4.4	59.2%	7858	7858	0
25	3430.8	238.0	251.8	23.62	3.0	105.3%	7443	7443	0
26	4883.3	259.5	256.1	26.27	4.4	58.9%	7399	7399	0
27	1403.1	208.0	96.7	26.82	3.9	70.4%	2893	2893	0
28	2164.9	219.3	70.3	35.19	11.0	0.0%	2683	0	0
29	12629.8	374.3	1353.9	20.63	1.9	274.6%	40819	40819	40819
30	8920.9	319.4	1224.6	19.85	1.5	504.7%	36683	36683	36683
31	4269.8	250.5	311.3	23.00	2.9	113.1%	9488	9488	9488
32	4098.8	247.9	406.7	21.42	2.2	192.1%	12023	12023	12023
33	10597.8	344.2	1063.9	20.52	1.9	244.5%	31483	31483	31483
34	1163.0	204.4	81.8	27.81	3.9	71.5%	2418	2418	0
35	1982.4	216.6	72.9	32.66	9.1	14.2%	2179	0	0

PROJECT/CASE STUDY DETAILED RESULTS (Cont'd) Case 4 - Investment Grants

	-- Updated Parameters --				-- Financial --		---- Cogeneration Potential ----		
Seq.	Increm Capital Cost (Base$k)	Increm O/M Cost (Base$k)	Increm Fuel Cons. (TJ)	Economic Supply Price ($/MWh)	Pay Back* (yrs)	Equity Return* (%)	Econ (kW)	Fin (kW)	Impl (kW)
36	3449.8	238.3	275.9	23.55	2.9	113.0%	7213	7213	7213
37	12249.8	368.7	1557.8	19.28	1.5	577.6%	48003	48003	48003
38	3153.2	233.9	191.1	25.95	4.0	68.1%	5745	5745	0
39	4520.8	254.2	403.5	21.88	2.4	157.4%	12403	12403	12403
40	3147.9	233.8	228.7	23.89	3.1	101.3%	6753	6753	0
41	17075.3	440.2	1549.1	20.76	2.2	190.4%	45843	45843	45843
42	2605.9	225.8	129.9	27.30	4.8	52.4%	3931	3931	0
43	2475.6	223.9	254.3	22.62	2.3	169.2%	7483	7483	7483
44	2626.0	226.1	128.3	28.72	5.5	41.6%	5728	0	0
45	1526.4	209.8	37.0	41.72	11.0	0.0%	2152	0	0
46	2437.0	223.3	120.4	27.94	4.3	61.7%	3603	3603	0
47	6179.8	278.8	87.2	43.68	11.0	0.0%	15315	0	0
48	2119.8	218.6	139.3	26.44	4.0	68.6%	4193	4193	0
49	2629.8	226.2	67.4	37.13	11.0	0.0%	3146	0	0
50	3648.4	241.3	48.1	52.69	11.0	0.0%	0	0	0
51	3453.9	238.4	199.0	26.17	4.2	63.9%	5743	5743	0
52	2326.3	221.7	152.1	26.17	3.9	70.7%	5259	5259	0
53	1426.4	208.3	81.6	29.04	5.3	43.2%	2403	0	0
54	2831.8	229.2	290.7	21.84	2.2	192.7%	8593	8593	8593
55	1788.8	213.7	88.2	29.55	5.9	36.7%	2643	0	0
56	1650.9	211.7	42.2	40.50	11.0	0.0%	2803	0	0
57	125.0	1.0	2.8	35.80	9.2	19.8%	50	0	0
58	150.0	6.0	10.5	17.14	2.8	123.3%	200	200	200
59	125.0	1.0	2.8	53.51	11.0	0.0%	0	0	0
60	1430.0	63.8	61.0	15.81	1.9	263.8%	2000	2000	2000
61	773.7	23.0	73.8	37.43	11.0	0.0%	1600	0	0
62	1875.0	48.0	106.5	23.64	2.9	114.9%	3000	3000	3000
63	990.0	141.5	106.5	37.72	11.0	0.0%	2000	0	0
64	876.5	108.0	215.2	72.14	11.0	0.0%	0	0	0
65	1360.0	70.0	35.1	41.26	11.0	0.0%	3000	0	0
66	740.0	65.0	32.6	35.82	9.0	12.0%	1500	0	0
	277998	15004	20979	26.88	4.9	116.2%			

* - Payback Period of 11.0 years and/or Equity Return of 0.0% indicates that the project is not feasible within its first ten years of operation.

** - Equity Return exceeds 800%

SUMMARY BY REPORT GROUP

Case 4 - Investment Grants

						----- Cogeneration Potential -----					--------- Total Potential --------			
Sector	Sub-Sector	Heat Demand Category	Report Group	Average Supply Price ($/MWh)	Average Payback Period (yrs)	Technical (kW)	Econ (kW)	Fin (kW)	Implem (kW)	Upgrade Factor	Tech (MW)	Econ (MW)	Fin (MW)	Implem (MW)
Industry	- Pulp & Paper	Low	111	35.80	9.2	50	50	0	0	91	4.6	4.6	0.0	0.0
		Medium	112	17.14	2.8	200	200	200	200	41	8.2	8.2	8.2	8.2
		High	113	14.75	2.2	181274	181274	181274	164669	2.125	385.2	385.2	385.2	349.9
	- Iron & Steel	High	123	23.01	3.0	79045	79055	79055	63755	2.25	177.9	177.9	177.9	143.4
	- Smelting	High	133	24.96	3.5	11408	11413	11413	7483	5	57.0	57.1	57.1	37.4
	- Petroleum	High	143	22.55	2.7	125942	125958	125958	113460	1.83	230.5	230.5	230.5	207.6
	- Chemicals	High	153	24.61	3.7	145862	145885	143203	130494	1.8	262.6	262.6	257.8	234.9
	- All Other	Low	191	53.51	11.0	50	0	0	0	583	29.2	0.0	0.0	0.0
		Medium	192	15.81	1.9	2000	2000	2000	2000	230	460.0	460.0	460.0	460.0
		High	193	34.19	7.2	115618	101813	58007	8593	3.5	404.7	356.3	203.0	30.1
Institutional	- Universites	Medium	212	37.43	11.0	1600	1600	0	0	9	14.4	14.4	0.0	0.0
		High	213	23.64	2.9	3000	3000	3000	3000	6	18.0	18.0	18.0	18.0
	- Hospitals	Medium	222	37.72	11.0	2000	2000	0	0	39	78.0	78.0	0.0	0.0
Commercial	- Large Malls	Medium	312	72.14	11.0	3000	0	0	0	101	303.0	0.0	0.0	0.0
	- Offices	Medium	322	41.26	11.0	3000	3000	0	0	153	459.0	459.0	0.0	0.0
Residential	- Apartments	Low	411	35.82	9.0	1500	1500	0	0	881	1321.5	1321.5	0.0	0.0
											4213.6	3833.2	1797.6	1489.6

PROJECT/CASE STUDY DETAILED RESULTS Case 5 - Longer Payback Period

	-- Updated Parameters --				-- Financial --		---- Cogeneration ----		
	Increm	Increm	Increm	Economic					
	Capital	O/M	Fuel	Supply	Pay	Equity		Potential	
Seq.	Cost	Cost	Cons.	Price	Back*	Return*	Econ	Fin	Impl
	(Base$k)	(Base$k)	(TJ)	($/MWh)	(yrs)	(%)	(kW)	(kW)	(kW)
1	8329.7	310.6	777.5	10.89	1.8	224.9%	22034	22034	22034
2	9607.8	329.5	972.0	10.34	1.6	284.2%	29055	29055	29055
3	8000.0	305.7	602.9	11.60	2.0	167.7%	19276	19276	19276
4	7368.7	296.4	331.4	17.02	3.8	54.2%	9650	9650	9650
5	6306.2	280.6	800.2	9.70	1.3	698.9%	22870	22870	22870
6	1879.5	215.0	95.7	22.07	4.5	41.1%	2720	2720	2720
7	8888.6	318.9	416.5	16.15	3.4	63.7%	12562	12562	12562
8	2697.6	227.2	132.2	20.02	4.1	47.2%	4235	4235	4235
9	4407.4	252.5	256.2	15.14	2.9	83.5%	8926	8926	8926
10	3618.7	240.8	205.8	16.05	3.1	76.4%	6167	6167	6167
11	4030.0	246.9	305.0	13.55	2.3	125.9%	10079	10079	10079
12	2949.0	230.9	212.8	14.97	2.5	105.7%	6248	6248	6248
13	5189.5	264.1	429.0	12.26	2.0	174.1%	14905	14905	14905
14	3217.0	234.9	278.9	13.12	1.9	187.1%	8405	8405	8405
15	2483.4	224.0	137.5	18.36	3.5	61.7%	4142	4142	4142
16	2864.5	229.6	55.0	43.94	11.0	0.0%	2313	0	0
17	2642.0	226.3	168.3	26.00	4.8	35.3%	5313	5313	5313
18	3468.0	238.6	205.1	25.05	4.6	38.4%	8613	8613	8613
19	6996.3	290.8	69.1	59.55	11.0	0.0%	0	0	0
20	2889.8	230.0	73.4	36.86	11.0	0.0%	5128	0	0
21	5649.8	270.9	241.6	28.08	5.8	28.2%	16693	16693	0
22	5773.4	272.7	467.7	21.87	3.1	73.3%	16803	16803	16803
23	16448.8	430.9	1586.8	20.49	2.6	101.5%	46953	46953	46953
24	4980.1	261.0	249.7	26.06	5.4	29.5%	7858	7858	0
25	3430.8	238.0	251.8	23.62	3.7	54.7%	7443	7443	7443
26	4883.3	259.5	256.1	26.27	5.4	29.2%	7399	7399	0
27	1403.1	208.0	96.7	26.82	4.8	34.6%	2893	2893	2893
28	2164.9	219.3	70.3	35.19	11.0	0.0%	2683	0	0
29	12629.8	374.3	1353.9	20.63	2.3	130.7%	40819	40819	40819
30	8920.9	319.4	1224.6	19.85	1.9	196.6%	36683	36683	36683
31	4269.8	250.5	311.3	23.00	3.5	58.8%	9488	9488	9488
32	4098.8	247.9	406.7	21.42	2.6	96.9%	12023	12023	12023
33	10597.8	344.2	1063.9	20.52	2.4	119.1%	31483	31483	31483
34	1163.0	204.4	81.8	27.81	4.7	36.9%	2418	2418	2418
35	1982.4	216.6	72.9	32.66	11.0	0.0%	2179	0	0

PROJECT/CASE STUDY DETAILED RESULTS (Cont'd) Case 5 - Longer Payback Period

	-- Updated Parameters --				-- Financial --		---- Cogeneration ----		
	Increm	Increm	Increm	Economic				Potential	
	Capital	O/M	Fuel	Supply	Pay	Equity			
Seq.	Cost	Cost	Cons.	Price	Back*	Return*	Econ	Fin	Impl
	(Base$k)	(Base$k)	(TJ)	($/MWh)	(yrs)	(%)	(kW)	(kW)	(kW)
36	3449.8	238.3	275.9	23.55	3.5	58.6%	7213	7213	7213
37	12249.8	368.7	1557.8	19.28	1.8	212.2%	48003	48003	48003
38	3153.2	233.9	191.1	25.95	4.9	34.1%	5745	5745	5745
39	4520.8	254.2	403.5	21.88	2.9	80.9%	12403	12403	12403
40	3147.9	233.8	228.7	23.89	3.8	52.5%	6753	6753	6753
41	17075.3	440.2	1549.1	20.76	2.7	96.5%	45843	45843	45843
42	2605.9	225.8	129.9	27.30	5.8	25.3%	3931	3931	0
43	2475.6	223.9	254.3	22.62	2.8	86.6%	7483	7483	7483
44	2626.0	226.1	128.3	28.72	6.8	18.9%	5728	5728	0
45	1526.4	209.8	37.0	41.72	11.0	0.0%	2152	0	0
46	2437.0	223.3	120.4	27.94	5.3	33.0%	3603	3603	0
47	6179.8	278.8	87.2	43.68	11.0	0.0%	15315	0	0
48	2119.8	218.6	139.3	26.44	4.9	34.2%	4193	4193	4193
49	2629.8	226.2	67.4	37.13	11.0	0.0%	3146	0	0
50	3648.4	241.3	48.1	52.69	11.0	0.0%	0	0	0
51	3453.9	238.4	199.0	26.17	5.1	31.8%	5743	5743	0
52	2326.3	221.7	152.1	26.17	4.8	35.3%	5259	5259	5259
53	1426.4	208.3	81.6	29.04	6.6	18.4%	2403	2403	0
54	2831.8	229.2	290.7	21.84	2.6	97.3%	8593	8593	8593
55	1788.8	213.7	88.2	29.55	7.3	15.0%	2643	2643	0
56	1650.9	211.7	42.2	40.50	11.0	0.0%	2803	0	0
57	125.0	1.0	2.8	35.80	11.0	0.0%	50	0	0
58	150.0	6.0	10.5	17.14	3.4	65.0%	200	200	200
59	125.0	1.0	2.8	53.51	11.0	0.0%	0	0	0
60	1430.0	63.8	61.0	15.81	2.3	125.9%	2000	2000	2000
61	773.7	23.0	73.8	37.43	11.0	0.0%	1600	0	0
62	875.0	48.0	106.5	23.64	3.5	60.0%	3000	3000	3000
63	990.0	141.5	106.5	37.72	11.0	0.0%	2000	0	0
64	876.5	108.0	215.2	72.14	11.0	0.0%	0	0	0
65	1360.0	70.0	35.1	41.26	11.0	0.0%	3000	0	0
66	740.0	65.0	32.6	35.82	11.0	0.0%	1500	0	0
	277998	15004	20979	26.88	5.6	70.3%			

* - Payback Period of 11.0 years and/or Equity Return of 0.0% indicates that the project is not feasible within its first ten years of operation.

SUMMARY BY REPORT GROUP

Case 5 - Longer Payback Periods

						----- Cogeneration Potential -----					--------- Total Potential --------			
Sector	Sub-Sector	Heat Demand Category	Report Group	Average Supply Price ($/MWh)	Average Payback Period (yrs)	Technical (kW)	Econ (kW)	Fin (kW)	Implen (kW)	Upgrade Factor	Tech (MW)	Econ (MW)	Fin (MW)	Implem (MW)
Industry	- Pulp & Paper	Low	111	35.80	11.0	50	50	0	0	91	4.6	4.6	0.0	0.0
		Medium	112	17.14	3.4	200	200	200	200	41	8.2	8.2	8.2	8.2
		High	113	14.75	2.7	181274	181274	181274	181274	2.125	385.2	385.2	385.2	385.2
	- Iron & Steel	High	123	23.01	3.7	79045	79055	79055	71198	2.25	177.9	177.9	177.9	160.2
	- Smelting	High	133	24.96	4.3	11408	11413	11413	7483	5	57.0	57.1	57.1	37.4
	- Petroleum	High	143	22.55	3.3	125942	125958	125958	125958	1.83	230.5	230.5	230.5	230.5
	- Chemicals	High	153	24.61	4.3	145862	145885	143203	135804	1.8	262.6	262.6	257.8	244.4
	- All Other	Low	191	53.51	11.0	50	0	0	0	583	29.2	0.0	0.0	0.0
		Medium	192	15.81	2.3	2000	2000	2000	2000	230	460.0	460.0	460.0	460.0
		High	193	34.19	7.9	115618	101813	68780	31969	3.5	404.7	356.3	240.7	111.9
Institutional	- Universites	Medium	212	37.43	11.0	1600	1600	0	0	9	14.4	14.4	0.0	0.0
		High	213	23.64	3.5	3000	3000	3000	3000	6	18.0	18.0	18.0	18.0
	- Hospitals	Medium	222	37.72	11.0	2000	2000	0	0	39	78.0	78.0	0.0	0.0
Commercial	- Large Malls	Medium	312	72.14	11.0	3000	0	0	0	101	303.0	0.0	0.0	0.0
	- Offices	Medium	322	41.26	11.0	3000	3000	0	0	153	459.0	459.0	0.0	0.0
Residential	- Apartments	Low	411	35.82	11.0	1500	1500	0	0	881	1321.5	1321.5	0.0	0.0
											4213.6	3833.2	1835.3	1655.9

PROJECT/CASE STUDY DETAILED RESULTS

Case 6 - Shorter Payback Period

	-- Updated Parameters --				-- Financial --		---- Cogeneration ----		
	Increm	Increm	Increm	Economic			Potential		
Seq.	Capital Cost (Base$k)	O/M Cost (Base$k)	Fuel Cons. (TJ)	Supply Price ($/MWh)	Pay Back* (yrs)	Equity Return* (%)	Econ (kW)	Fin (kW)	Impl (kW)
1	8329.7	310.6	777.5	10.89	1.8	224.9%	22034	22034	22034
2	9607.8	329.5	972.0	10.34	1.6	284.2%	29055	29055	29055
3	8000.0	305.7	602.9	11.60	2.0	167.7%	19276	19276	0
4	7368.7	296.4	331.4	17.02	3.8	54.2%	9650	0	0
5	6306.2	280.6	800.2	9.70	1.3	698.9%	22870	22870	22870
6	1879.5	215.0	95.7	22.07	4.5	41.1%	2720	0	0
7	8888.6	318.9	416.5	16.15	3.4	63.7%	12562	0	0
8	2697.6	227.2	132.2	20.02	4.1	47.2%	4235	0	0
9	4407.4	252.5	256.2	15.14	2.9	83.5%	8926	8926	0
10	3618.7	240.8	205.8	16.05	3.1	76.4%	6167	0	0
11	4030.0	246.9	305.0	13.55	2.3	125.9%	10079	10079	0
12	2949.0	230.9	212.8	14.97	2.5	105.7%	6248	6248	0
13	5189.5	264.1	429.0	12.26	2.0	174.1%	14905	14905	14905
14	3217.0	234.9	278.9	13.12	1.9	187.1%	8405	8405	8405
15	2483.4	224.0	137.5	18.36	3.5	61.7%	4142	0	0
16	2864.5	229.6	55.0	43.94	11.0	0.0%	2313	0	0
17	2642.0	226.3	168.3	26.00	4.8	35.3%	5313	0	0
18	3468.0	238.6	205.1	25.05	4.6	38.4%	8613	0	0
19	6996.3	290.8	69.1	59.55	11.0	0.0%	0	0	0
20	2889.8	230.0	73.4	36.86	11.0	0.0%	5128	0	0
21	5649.8	270.9	241.6	28.08	5.8	28.2%	16693	0	0
22	5773.4	272.7	467.7	21.87	3.1	73.3%	16803	0	0
23	16448.8	430.9	1586.8	20.49	2.6	101.5%	46953	46953	0
24	4980.1	261.0	249.7	26.06	5.4	29.5%	7858	0	0
25	3430.8	238.0	251.8	23.62	3.7	54.7%	7443	0	0
26	4883.3	259.5	256.1	26.27	5.4	29.2%	7399	0	0
27	1403.1	208.0	96.7	26.82	4.8	34.6%	2893	0	0
28	2164.9	219.3	70.3	35.19	11.0	0.0%	2683	0	0
29	12629.8	374.3	1353.9	20.63	2.3	130.7%	40819	40819	0
30	8920.9	319.4	1224.6	19.85	1.9	196.6%	36683	36683	36683
31	4269.8	250.5	311.3	23.00	3.5	58.8%	9488	0	0
32	4098.8	247.9	406.7	21.42	2.6	96.9%	12023	12023	0
33	10597.8	344.2	1063.9	20.52	2.4	119.1%	31483	31483	0
34	1163.0	204.4	81.8	27.81	4.7	36.9%	2418	0	0
35	1982.4	216.6	72.9	32.66	11.0	0.0%	2179	0	0

PROJECT/CASE STUDY DETAILED RESULTS (Cont'd) Case 6 - Shorter Payback Period

	-- Updated Parameters --				-- Financial --		---- Cogeneration ----		
	Increm	Increm	Increm	Economic					
	Capital	O/M	Fuel	Supply	Pay	Equity		Potential	
Seq.	Cost	Cost	Cons.	Price	Back*	Return*	Econ	Fin	Impl
	(Base$k)	(Base$k)	(TJ)	($/MWh)	(yrs)	(%)	(kW)	(kW)	(kW)
36	3449.8	238.3	275.9	23.55	3.5	58.6%	7213	0	0
37	12249.8	368.7	1557.8	19.28	1.8	212.2%	48003	48003	48003
38	3153.2	233.9	191.1	25.95	4.9	34.1%	5745	0	0
39	4520.8	254.2	403.5	21.88	2.9	80.9%	12403	12403	0
40	3147.9	233.8	228.7	23.89	3.8	52.5%	6753	0	0
41	17075.3	440.2	1549.1	20.76	2.7	96.5%	45843	45843	0
42	2605.9	225.8	129.9	27.30	5.8	25.3%	3931	0	0
43	2475.6	223.9	254.3	22.62	2.8	86.6%	7483	7483	0
44	2626.0	226.1	128.3	28.72	6.8	18.9%	5728	0	0
45	1526.4	209.8	37.0	41.72	11.0	0.0%	2152	0	0
46	2437.0	223.3	120.4	27.94	5.3	33.0%	3603	0	0
47	6179.8	278.8	87.2	43.68	11.0	0.0%	15315	0	0
48	2119.8	218.6	139.3	26.44	4.9	34.2%	4193	0	0
49	2629.8	226.2	67.4	37.13	11.0	0.0%	3146	0	0
50	3648.4	241.3	48.1	52.69	11.0	0.0%	0	0	0
51	3453.9	238.4	199.0	26.17	5.1	31.8%	5743	0	0
52	2326.3	221.7	152.1	26.17	4.8	35.3%	5259	0	0
53	1426.4	208.3	81.6	29.04	6.6	18.4%	2403	0	0
54	2831.8	229.2	290.7	21.84	2.6	97.3%	8593	8593	0
55	1788.8	213.7	88.2	29.55	7.3	15.0%	2643	0	0
56	1650.9	211.7	42.2	40.50	11.0	0.0%	2803	0	0
57	125.0	1.0	2.8	35.80	11.0	0.0%	50	0	0
58	150.0	6.0	10.5	17.14	3.4	65.0%	200	0	0
59	125.0	1.0	2.8	53.51	11.0	0.0%	0	0	0
60	1430.0	63.8	61.0	15.81	2.3	125.9%	2000	2000	0
61	773.7	23.0	73.8	37.43	11.0	0.0%	1600	0	0
62	1875.0	48.0	106.5	23.64	3.5	60.0%	3000	0	0
63	990.0	141.5	106.5	37.72	11.0	0.0%	2000	0	0
64	876.5	108.0	215.2	72.14	11.0	0.0%	0	0	0
65	1360.0	70.0	35.1	41.26	11.0	0.0%	3000	0	0
66	740.0	65.0	32.6	35.82	11.0	0.0%	1500	0	0
	277998	15004	20979	26.88	5.6	70.3%			

* - Payback Period of 11.0 years and/or Equity Return of 0.0% indicates that the project is not feasible within its first ten years of operation.

SUMMARY BY REPORT GROUP

Case 6 - Shorter Payback Periods

Sector	Sub-Sector	Heat Demand Category	Report Group	Average Supply Price ($/MWh)	Average Payback Period (yrs)	----- Cogeneration Potential ----- Technical (kW)	Econ (kW)	Fin (kW)	Implem (kW)	Upgrade Factor	--------- Total Potential -------- Tech (MW)	Econ (MW)	Fin (MW)	Implem (MW)
Industry	- Pulp & Paper	Low	111	35.80	11.0	50	50	0	0	91	4.6	4.6	0.0	0.0
		Medium	112	17.14	3.4	200	200	0	0	41	8.2	8.2	0.0	0.0
		High	113	14.75	2.7	181274	181274	141798	97269	2.125	385.2	385.2	301.3	206.7
	- Iron & Steel	High	123	23.01	3.7	79045	79055	46953	0	2.25	177.9	177.9	105.6	0.0
	- Smelting	High	133	24.96	4.3	11408	11413	7483	0	5	57.0	57.1	37.4	0.0
	- Petroleum	High	143	22.55	3.3	125942	125958	106248	48003	1.83	230.5	230.5	194.4	87.8
	- Chemicals	High	153	24.61	4.3	145862	145885	121006	36683	1.8	262.6	262.6	217.8	66.0
	- All Other	Low	191	53.51	11.0	50	0	0	0	583	29.2	0.0	0.0	0.0
		Medium	192	15.81	2.3	2000	2000	2000	0	230	460.0	460.0	460.0	0.0
		High	193	34.19	7.9	115618	101813	8593	0	3.5	404.7	356.3	30.1	0.0
Institutional	- Universites	Medium	212	37.43	11.0	1600	1600	0	0	9	14.4	14.4	0.0	0.0
		High	213	23.64	3.5	3000	3000	0	0	6	18.0	18.0	0.0	0.0
	- Hospitals	Medium	222	37.72	11.0	2000	2000	0	0	39	78.0	78.0	0.0	0.0
Commercial	- Large Malls	Medium	312	72.14	11.0	3000	0	0	0	101	303.0	0.0	0.0	0.0
	- Offices	Medium	322	41.26	11.0	3000	3000	0	0	153	459.0	459.0	0.0	0.0
Residential	- Apartments	Low	411	35.82	11.0	1500	1500	0	0	881	1321.5	1321.5	0.0	0.0
											4213.6	3833.2	1346.7	360.6

PROJECT/CASE STUDY LIST

				Existing Plant					Cogeneration Parameters					
						In-House Generating			Potential Cogenerating		Incremental			
Seq.	Ref.	S.I.C. Sub-Sector	Report Group	Elec. Demand (kW)	Annual Energy Cons. (GWh)	Cap. (kW)	Energy (GWh)	Fuel Type	Cap. (kW)	Energy (GWh)	Capital Cost (CD$k)	Fuel Cons. (GBtu)	Add'l Oper Costs (CD$k)	Cost Datum (CD)
1	13	271	113	64000	490.0	9600	73.5	Coal/Oil	22034	177.1	8329.7	737.1	0	1979
2	17	271	113	93000	730.0	6500	51.0	Oil/Gas/	29055	221.4	9607.8	921.5	0	1979
3	37	271	113	28800	158.6	16600	72.7	C/O/B	19276	144.9	8000.0	571.6	0	1979
4	54	271	113	62000	434.0	-	-	Gas	9650	75.5	7368.7	314.2	0	1979
5	64	271	113	36500	200.0	6200	48.0	Gas/Liqr	22870	182.3	6306.2	758.6	0	1979
6	67	271	113	7400	46.1	-	-	Gas/Oil	2720	21.8	1879.5	90.7	0	1979
7	72	271	113	13500	93.9	7600	47.0	Gas/W	12562	94.9	8888.6	394.9	0	1979
8	75	271	113	7100	46.3	-	-	Gas	4235	30.1	2697.6	125.3	0	1979
9	136	271	113	10201	70.0	-	-	Oil	8926	60.5	4407.4	242.9	0	1979
10	166	271	113	10000	65.0	-	-	Gas/Coal	6167	48.6	3618.7	195.1	0	1979
11	169	271	113	31412	237.1	-	-	Gas	10079	69.5	4030.0	289.2	0	1979
12	170	271	113	36000	265.0	-	-	Gas/Wood	6248	48.5	2949.0	201.7	0	1979
13	171	271	113	13500	93.9	7600	47.0	Wood/Liq	14905	98.2	5189.5	406.7	0	1979
14	173	271	113	-	-	-	-	Gas/Wood	8405	63.5	3217.0	264.4	0	1979
15	181	271	113	26800	181.0	-	-	Oil/Wood	4142	32.1	2483.4	130.4	0	1979
16	38	10	193	5748	32.5	-	-	Gas/Oil	2310	12.4	2864.8	51.6	0	1979
17	89	10	193	1080	60.0	-	-	Gas	5310	38.2	2642.3	159.0	0	1979
18	127	10	193	10000	78.0	-	-	Gas	8610	48.3	3468.2	193.9	0	1979
19	140	10	193	6700	16.0	-	-	Gas/Oil	7832	15.8	6996.5	54.9	0	1979
20	36	11	193	1400	-	-	-	Oil	5125	17.2	2890.0	69.0	0	1979
21	115	11	193	6400	32.6	6000	27.7	Gas	16690	54.9	5650.0	228.5	0	1979
22	137	291	123	180000	1221.0	-	-	Oil	16800	110.3	5773.7	442.8	0	1979
23	187	291	123	146250	946.0	3750	40.0	Gas/Oil	46950	370.1	16449.0	1503.8	0	1979
24	188	291	123	40000	220.0	-	-	Oil	7855	58.1	4980.3	236.1	0	1979
25	204	291	123	144000	930.0	-	-	Gas/Oil	7440	58.6	3431.0	238.1	0	1979
26	71	378	153	43000	325.0	-	-	Gas	7396	58.2	4883.6	242.2	0	1979
27	84	378	153	23000	170.0	-	-	Oil	2890	22.7	1403.3	91.1	0	1979
28	91	378	153	10000	54.0	-	-	Gas	2680	15.9	2165.1	66.1	0	1979
29	98	378	153	28000	216.2	18600	146.0	Gas	40816	308.3	12630.0	1283.0	0	1979
30	107	378	153	22500	168.0	-	-	Oil	36680	278.8	8921.1	1160.4	0	1979
31	108	378	153	10000	74.0	-	-	Oil	9485	73.3	4270.0	294.5	0	1979
32	182	378	153	18720	130.1	-	-	Gas/Oil	12020	94.8	4099.0	385.0	0	1979
33	191	378	153	13500	115.0	-	-	Gas/Oil	31480	248.0	10598.0	1008.0	0	1979
34	217	378	153	25500	11.0	-	-	Gas/Oil	2415	19.0	1163.3	77.0	0	1979
35	139	19	193	12670	95.4	-	-	Oil	2176	17.1	1982.7	68.5	0	1979

PROJECT/CASE STUDY LIST

				Existing Plant					Cogeneration Parameters					
Seq.	Ref.	S.I.C. Sub-Sector	Report Group	Elec. Demand (kW)	Annual Energy Cons. (GWh)	In-House Generating Cap. (kW)	In-House Generating Energy (GWh)	Fuel Type	Potential Cogenerating Cap. (kW)	Potential Cogenerating Energy (GWh)	Incremental Capital Cost (CD$k)	Incremental Fuel Cons. (GBtu)	Add'l Oper Costs (CD$k)	Cost Datum (CD)
36	34	365	143	16600	117.0	-	-	Gas	7210	62.7	3450.0	261.0	0	1979
37	79	365	143	13400	97.5	-	-	Oil	48000	367.7	12250.0	1476.3	0	1979
38	138	365	143	12480	68.4	2600	21.8	Gas	5742	43.4	3153.5	180.6	0	1979
39	213	365	143	18500	123.9	-	-	Gas/Oil	12400	94.0	4521.0	382.0	0	1979
40	214	365	143	18500	146.0	-	-	Gas/Oil	6750	53.2	3148.1	216.2	0	1979
41	221	365	143	28000	264.0	-	-	Gas/Oil	45840	361.4	17075.5	1468.0	0	1979
42	106	5	133	30122	180.3	-	-	Oil	3928	30.9	2606.2	122.6	0	1979
43	135	5	133	150000	1000.0	-	-	Gas	7480	57.8	2475.9	240.5	0	1979
44	76	39	193	43500	264.0	5300	18.5	Gas	5725	29.1	2626.2	121.1	0	1979
45	87	39	193	14000	66.0	1400	3.3	Oil	2149	8.6	1526.6	34.5	0	1979
46	104	39	193	0	0.0	-	-	Oil	3600	28.3	2437.3	113.6	0	1979
47	113	39	193	26000	160.3	-	-	-	15312	22.3	6180.0	82.1	0	1979
48	121	39	193	15000	61.0	750	9.1	Gas	4190	31.6	2120.0	131.5	0	1979
49	122	39	193	13500	70.8	-	-	Oil	3143	15.8	2630.0	63.3	0	1979
50	153	39	193	8294	40.3	-	-	Gas/Oil	6020	10.8	3648.6	45.0	0	1979
51	154	39	193	24000	160.0	-	-	Gas/Oil	5740	45.2	3454.2	188.1	0	1979
52	172	39	193	8525	75.2	-	-	Gas/Coal	5256	34.5	2326.5	143.6	0	1979
53	192	39	193	16000	88.0	-	-	Oil	2400	18.9	1426.6	76.8	0	1979
54	193	39	193	47720	256.0	-	-	Oil	8590	67.7	2832.0	275.0	0	1979
55	194	39	193	0	39.3	-	-	Gas/Coal	2640	20.5	1789.0	83.0	0	1979
56	195	39	193	10000	55.0	-	-	Oil	2800	9.7	1651.2	39.4	0	1979
57	501	271	111	444	5.6	-	-	Gas	50	0.4	125.0	2.7	1.0	1985
58	502	271	112	1000	4.7	-	-	Gas	200	1.8	150.0	10.0	6.0	1985
59	511	39	191	444	5.6	-	-	Gas	50	0.4	125.0	2.7	1.0	1985
60	512	39	192	1000	4.7	-	-	Gas	2000	25.5	1430.0	57.8	63.8	1985
61	514	50	212	6500	37.0	-	-	Gas	1600	10.4	773.7	70.0	23.0	1985
62	515	50	213	14400	77.0	-	-	Gas	3000	26.9	1875.0	101.0	48.0	1985
63	517	50	222	5500	24.5	-	-	Gas	2000	17.5	990.0	101.0	141.5	1985
64	520	60	312	3600	12.3	-	-	Gas	3000	14.8	876.5	204.0	108.0	1985
65	523	60	322	1750	9.5	-	-	Gas	3000	7.8	1360.0	33.3	70.0	1985
66	525	70	411	1500	7.5	-	-	Gas	1500	7.2	740.0	30.9	65.0	1985

APPENDIX D

NOTES ON INTERVIEWS

APPENDIX D

NOTES ON INTERVIEWS BARRIERS TO COGENERATION

Dupont Canada Inc. - Maitland Works, C.W. Laidley, Senior Engineer - Energy Conservation, 613-348-3611

- Five boilers, at 250 and 450 psig, produce steam for process and heating in a large petrochemical complex producing raw materials for nylon and similar products. The boilers are arranged to burn natural gas and/or oil and can produce 700 000 lb/h of steam, although actual use is rarely more than 500 000 lb/h, and frequently much less. The average electrical load for the plant is 17 MW with peaks to 19.5 MW.

- In 1981 Ontario Hydro carried out a cogeneration feasibility study for this plant and found the four alternatives investigated economically unacceptable, with simple payback periods between 4.5 and 7.0 years.

- Mr. Laidley recalled that one of the constraints in the 1981 study was the fact that existing boilers could only go up to 600 psig and that for cogeneration to be viable, higher differential pressures would be required; replacement of boilers would make cogeneration technically feasible but not so economically since existing boilers have remaining economic life.

- Furthermore, to adapt and augment existing plant equipment to provide cogeneration capability would involve process interruptions which would have to be taken into account in the analysis of viability. Only a new power plant with short hook-up time would minimize disruption.

- Because of its lack of feasibility, the 1981 study was never considered beyond the technical staff level, under the direction of the Chief Engineer. Hence, the analysis did not receive the more extensive scrutiny of the company's financial analysts who typically carry out more sophisticated after tax and after depreciation investment analyses. On that basis, the payback requirement is on he order of two to three years, depending on the size of the investment and the long-term prospects for the new venture. Presently, any type of major investment is scrutinized heavily since price instability continues to affect the industry.

- According to Mr. Laidley, the situation has changed since 1981. Because of the implementation of conservation measures and shutdown of certain processes, overall steam requirements are now substantially less. Even if replacement boilers were required today, cogeneration might be difficult to justify, since there is little incentive, or need to invest in new boilers.

- The Company's conservation program at the Maitland Works has now dealt with most major items of 'housekeeping'; at Maitland they are now moving towards capital conservation investments such as computerized operational controls. While the Company continues to look for other conservation opportunities, cogeneration is no longer being considered at Maitland.

Rio Algom Limited, Milliken Mine, Elliot Lake, Mr. W. Turner, Chief Engineer, 416-367-4000

- In 1981, Rio Algom was considering reopening and expanding the Milliken Uranium Mine near Elliot Lake. The milling operation would require 100 000 lbs/hr of steam for leaching processes, at a pressure of 250 psig. Peak electric power demand would be 39 300 kVA. Natural gas would be available. Four cogeneration alternatives were studied by Ontario Hydro, with the gas-fired boiler and back-pressure steam turbine alternative having the lowest capital cost - about $2.3 million - and the highest rate of return- about 55% or a simple payback of less than one year. The low incremental capital cost is on account of the cost of standby generation capacity which would be required in any event; with cogeneration a continuous-duty small back-pressure steam turbine would act as backup power supply.

- As it turned out, Milliken mine never opened. However, at Quirke Mine, also in Elliot Lake, a definite potential might exist. According to Mr. Turner, a dual gas-steam turbine, waste-heat boiler and other equipment for a new cogeneration plant would now cost on the order of $9 million. This would allow for 20 MW of electrical generation for site consumption. However, in the absence of specific government incentives, no full-fledged feasibility study by consultants would be undertaken.

- Typically, management looks at a 2-year payback period, although for a cogeneration plant they might go as far as 4 years. Much would depend on the gas price that the Company could negotiate with Alberta producers.

- The Company has a $25 million annual energy bill at Elliot Lake; it also has active energy conservation and management programs. One-year payback measures have mostly been implemented and capital expenditures up to 3-year payback can be authorized by the mine manager; anything over 3 years requires corporate approval.

- Management's attitude is 'we're in the mining business', and hence a major cogeneration expenditure would not likely be considered without incentives to bring the payback to less than 4 years. Also, there would need to be guarantees that there would be 'no problems with the utility', and, of course, capital for investment would have to be available at reasonable rates. Particularly, the utility's position on standby charges and peak charges should be eased.

- Technically, Mr. Turner did not see a problem with implementation, or with the environment since gas would be the fuel.

- Like any investment opportunity, a well-documented and attractive case would need to be prepared before cogeneration - not exactly a household word in the boardroom - could be seriously considered.

Sunnybrook Hospital, Toronto, Mr. Bernard Deuchars, Chief Engineer, 416-486-3000

- Sunnybrook, with 1100 beds, is the second largest hospital in Canada; it has a floor area of 1 400 000 ft^2.

- Steam usage per month runs from 7.75 million pounds in summer to 23.00 million pounds in winter.

- Mr. Deuchars is quite familiar with the cogeneration concept but voiced the opinion that in a retrofit situation, which would be the case at Sunnybrook, a cogeneration facility might not be financially viable, i.e. generate enough savings. To back up his opinion, Mr. Deuchars mentioned that on two different occasions, consultants had carried out energy studies for the hospital with neither suggesting cogeneration for further study consideration.

- A precondition to examining cogeneration for the hospital would be 100% outside funding for the investigation, according to Mr. Deuchars.

- An institution such as Sunnybrook doesn't always work on the payback principle in evaluating capital expenditures, since many of these expenditures are made for non-financial reasons, such as state-of-the-art medical equipment.

- A cogeneration facility would compete with other capital items in the capital budget which is provided/approved by the Ministry of Health. Unless there is quite a significant actual or perceived advantage to a new capital item, it usually doesn't get funded, unless replacement is in order. As such, cogeneration as a priority might have a difficult time competing for funding.

- A cogeneration facility, to be seriously considered, would likely have to be financed from outside, i.e. not out of hospital funds, and pay for itself.

- Mr. Deuchars cited a recent example of an incinerator to replace trucked waste which showed a 3-year payback through decreases in operation costs. Internal financing was suggested for the $1 million incinerator through borrowing from reserves, then repaying-without interest - out of the operating costs savings. This concept has not yet been approved.

- Mr. Deuchars also mentioned that for a sophisticated cogeneration facility - as compared to standard boiler operations - the skilled operating staff may be difficult to find within wage scales prevailing in the hospital environment.

- Finally, Mr. Deuchars mentioned that, even if feasible and approved, the risk attached to cost overruns for an unfamiliar facility such as a cogeneration plant, might be significant, especially if it were introduced as a retrofit. Apart from this, no other major planning problems would be foreseen.

Ontario Paper Company Ltd., Thorold, Mr. Loy Bonnaza, Energy Coordinator, 416-227-1121

- The existing steam plant contains five 150 000 lb/h natural gas-fired boilers, producing steam at 420 psig which is distributed as such within the 850 t/d newsprint mill; pressure reduction, as required, is at the point of use. No electric power is generated. A cogeneration study by consultants was carried out in 1986 which showed that (1) the gas-turbine generator alternatives show simple paybacks ranging from 3 to 5 years with the long-term advantage of the gas turbine depending on the future relationship between gas and electricity costs and (2) the bark- and coal-fired boiler alternatives show paybacks ranging from 4.1 to 5.3 years.

- Mr. Bonnaza indicated that beyond the pre-feasibility studies no decision had been made yet to proceed with the next step which would involve full feasibility and preliminary design. Although the payback periods as shown were not discouraging, there is usually a tendency for cost overruns.

- The Company's typical payback requirement is 2 years after taxes. However, for investments with strategic value or long-term effect, the payback can be between 3 and 5 years. Examples of strategic investments might be in the areas of project quality, safety, pollution control and energy security.

- Cogeneration would be considered a strategic issue since its introduction would make the Company more self-sufficient and would place it more on a par with other mills in the Province that already have the benefits of cogeneration.

- While the Company considers itself energy-efficient, with an above average energy to output ratio, there is a need to continue to look for energy cost reductions, especially since the plant is in a location where it cannot take direct advantage of hydro opportunities.

- Mr. Bonnaza felt that even though a cogeneration facility would not be selling to the grid (since its output would only be about half the total requirements), the arrangements with the utility would be critical in ensuring a successful project.

- In terms of technical implementation, there would be no special problems, while the operation and maintenance of a gas turbine would probably require higher level skills and procedures than for a steam turbine.

Canada Packers Inc., Toronto Plant, Mr. Norman Maderas, Facilities Manager, 416-766-4311

- Canada Packers' large processing plant purchases all its electrical energy from Toronto Hydro. Peak monthly consumption is 6 million kW.h. An existing gas- and oil-fired boiler plant generates steam for food processing, space heating and driving turbines for refrigeration equipment. Boilers produce either 50 000 or 100 000 lb/h of steam. The annual energy bill in 1980 was in excess of $5 million.

- Consultants evaluated a number of cogeneration alternatives in 1981. Those with the most potential were a new 2660-kW turbine generator or a new 6800-kW gas-turbine generator, both complete with exhaust gas waste-heat boiler. Capital costs were respectively $4 and $9 million; considering savings in operating costs, neither scheme would give an adequate payback period, with capital cost chargeable to cogeneration of $900 and $690/kW. Conversion of the existing boilers was considered impractical and costly.

- No cogeneration was installed at Canada Packers and considering developments since 1981 none will be installed in the future. The plant has closed its abattoir section which had a capacity of 1000 cattle per day and 6000 hogs per day; these operations have moved to plants elsewhere in the Province. Operations at the rendering plant have also been reduced. Hence, steam demand has dropped significantly, to about 65 000 lb/h (at 140 psig), with a further reduction to 35 000 lb/h foreseen. Electrical load has also been reduced. The turbine that was being used to drive a 700-ton screw compressor for refrigeration equipment is no longer being used.

- Mr. Maderas indicated that the Company's payback on energy conservation equipment is usually 1.5 years; there is no particular budget: if the DCF is all right, then funding is provided.

- Since 1980, Company-wide costs of water/power/fuel purchases have been about 40% less; the Company also regularly reports conservation progress through the industry food and beverage sector.

- As for cogeneration, there is at present no authentic reason to look at it again, even though there is excess steam capacity in the plant which employees 27 persons. However, the entire engine room will be relocated on the site within the next six months with no thought given to cogeneration.

Nestle Coffee Plant, Chesterville, Mr. Roy Maconachie, Director of Engineering Services, Toronto, 416-429-4411

- Steam for process heat comes from three natural gas burning boilers, with an average demand of 35 000 lb/h at 200 psig. Spent coffee grounds are also used as a fuel. Basic electric load is 800 kW with a peak as high as 2600 kW. The plant operates 24 h/d, 5 to 6 d/wk, for 50 wk/yr.

- A cogeneration study was carried out by Ontario Hydro in 1981. Using the simple payback period method (capital cost divided by first-year operating cost savings) all cogeneration alternatives studied were found to be uneconomical, with payback periods exceeding 10 years.

- Subsequently, Nestle installed a new boiler (at $1.5 million) for the sole purpose of burning coffee grounds. This has been the Company's largest capital energy conservation project to date. This biomass boiler now provides almost all the steam required, although two gas-fired boilers do produce steam in the occasional event that the supply of grounds is interrupted. The coffee grounds have a 55% moisture content which requires that some energy is expended on drying. Otherwise grounds are an excellent type of biomass. Economics was the main reason why the Company selected the single-purpose approach (produce steam only) rather than the dual cogeneration approach (produce steam and electricity).

- Depending on the factory and the product made (Nestle produces a wide range of food products in a variety of plants), the typical payback period required is 3 to 4 years. For products with a low risk long-term demand, a somewhat more generous payback can be allowed. Within reason, the supply of capital is not a problem if a proposed investment meets the criteria.

- Overall, the Company has made a significant improvement in energy usage, moving from 9000 Btu/lb of product produced in 1975, to about 7000 Btu at present. No direct energy saving can be calculated from these numbers because of the changing mix in product over the years.

- Beside grounds, there are no other suitable byproducts that lend themselves to fuel steam or electricity generation; furthermore, the Company is not in the business of electricity generation. This is what ultimately made the Company decide against cogeneration when an opportunity came along in California. It was found that other cogenerators using biomass had overestimated the supply and ended up buying from others including Nestle. Also, the utilities themselves started cogenerating, hence the incentive for individual firms was reduced. Since a long-term secure and seasonally even supply of waste is required, the risk to private operators is always there.

General Motors, Oshawa, Mr. R.D. Hughes, Senior Utilities Engineer, 416-644-5171

- GM's car and truck manufacturing plant, the largest plant in Ontario, has a maximum steam demand of 700 000 lb/h; the principal use for steam is for space heating, resulting in a low-load factor of 32%. The steam-generating plant has 6 coal-fired boilers, which are in good condition. Oshawa Hydro supplies all electricity: in 1980, consumption was 271 GW.h with an average demand of 48.8 MW.

- In 1981, consultants carried out a cogeneration feasibility study which showed that a 200 000 lb/h package boiler driving an 8-MW back-pressure steam turbine would be the most attractive scheme, although the most expensive to install on a unit cost basis. A scheme representing a 30-MW gas turbine and a waste-heat boiler was also found to be attractive. No payback periods were calculated.

- Mr. Hughes indicated that no cogeneration has been installed. Disruption might have been a factor as the coal boilers are maintained in the summer requiring the gas/oil boiler for ongoing steam demand. Since then, one coal boiler has been converted to gas/oil, allowing for more flexibility. There might also have been a problem with siting a new facility since space is at a premium. Then again, 30 MW may have been thought to be too high considering the state of the industry at that time. (Now General Motors is projecting a demand of 100 MW by 1990.) A 7.5-MW used turbine generator available from Ontario Hydro was considered for purchase but was not acquired.

- Most product-related investments require a simple payback period of 2 years, while energy-related investments require 3 years. Typically, there is 2-year advance planning for capital projects.

- Later this year, GM will be receiving its electricity directly from Ontario Hydro, thus reducing its cost.

- A large 100 t/d incinerator/boiler is presently being installed, for completion next year. This $10 million facility will be burning mostly wood and cardboard from incoming packaging. This plant's feasibility is based on (1) avoidance of landfill (2) displacement of some fuel and (3) capacity to generate steam. Cogeneration at this plant would have been difficult because of the lack of space; also the Company did not want to increase the capital cost. However, the boiler pressure is 600 psi, so future potential is there.

- Planning for the incinerator and 150-ft stack was simplified due to the fact that no waste was being brought in from outside the plant; this would have placed the facility in a different MOE category with more stringent requirements. The incinerator's location next to the powerhouse assists in the efficient deployment of trained operating staff.

- It is unlikely that cogeneration will receive any serious consideration over the next few years; then the engineering department's attention might well focus on peak-shaving measures such as direct-drive compressors for which there are excellent candidates.

Atlas Polar, Toronto, Mr. Frank Kocsis, Estimator, 416-751-7740

- Atlas Polar is a distributor of gas and diesel generator sets using US-made engines. The range is from about 75 to 2700 kW. In the last four years, 3 cogeneration packages have been sold in Ontario, as follows:

  - Peterborough Water Pollution Control Plant - 200-kW set operating on sewage gas,

  - University of Ottawa - 600-kW natural gas cogeneration set,

  - Folkema Farms - 12-kW biogas/propane cogeneration. Pig farm waste is heated through engine exhausts and heat exchanger to assist the production of biogas which is mixed with propane to provide the driving fuel for this equipment; excess heat is used for space heating. Propane is used to supplement the biogas to the appropriate calorific count.

- According to the Company, the equipment can be fully interconnected after utility requirements are met; it can be used for peak shaving in situations with irregular demand; it can allow for electricity to be sold back; or it can satisfy site-specific loads. Maintenance can be undertaken by the purchaser (a 5-day course is available) or by maintenance agreement. Under optimum conditions, the Company claims savings from 30 to 45%. Financing is the responsibility of the owner.

- A 12-kW unit could be appropriate for an electrically heated residential dwelling. However, the present installed cost is on the order of $15,000.

Abitibi-Price Ltd., Thunder Bay, Mr. Brian Morgan, Staff Engineer (Steam), 416-722-4770

- The Abitibi paper mill produces about 450 tonnes of newsprint per day and uses 150 000 lb/h of low-pressure steam. Two boilers are fired with natural gas and bark, about 50% each. Boiler 3 is used as standby. Since natural gas is sold on an interruptible basis, pulverized coal is used as standby fuel. No electricity is generated at the mill.

- A consultant's study in 1981 examined the feasibility of cogeneration and found that the steam producing facilities could be modified to produce high-pressure steam to turn a 9-MW turbine-generator set. In addition, a gas turbine rated at about 10 MW could be installed to provide more power, with its hot exhaust gases used as combustion air input to the boilers. This so-called combined cycle can be installed for about $7.5 million with a payback period of 5 years.

- Mr. Morgan, who recently completed a review of cogeneration for all four Ontario Abitibi-Price mills, indicated that the situation at the Thunder Bay plant had not changed since 1981. A company review of the feasibility study indicated some disagreement as to the potential payback period which in any event was too long to warrant serious investment consideration. In addition to looking 'iffy', Mr. Morgan cited competition of other company projects for available capital and not being in the electricity business as other reasons why no action was taken. Typically, the Company allows 4 years as the maximum threshold for investments of this type.

- The review undertaken by Mr. Morgan, showed a technical potential of up to 100 MW if the Company's Thunder Bay and Port Arthur loads were combined; with new boilers, a 30-mill buyback rate and a 25% capital grant, a simple payback of 4.8 years was estimated.

- For the Iroquois Falls plant, assuming all biomass fuel for a new 20-MW plant and a buyback rate of 30 mills, a payback of 2.8 years was estimated; this plant would replace purchased gas. At the present time, Woodex pellets are also used as a supplementary fuel. This plant would seem to have the best potential.

- Mr. Morgan suggested that technology is not a problem, especially now that cogeneration plants have been erected in the United States in significant numbers. Neither is implementation a problem. From the Company's point of view, it is essential that there is operational flexibility: this requires workable wheeling, standby, interconnection and purchase arrangements with the utility. Ultimately, the Company has to 'live' with the utility on a day-to-day basis and, to this end, US-type cogeneration legislation may well be required. If the Company is to perform a utility-type function, it should have access to utility-type arrangements that recognize this.

Petrosar Limited, Sarnia, Mr. E. Debevc, Energy Maintenance Coordinator, 519-862-2911

- The refinery, now owned by Polysar Corporation, has a capacity to process 170 000 barrels of crude oil per day and can produce ethylene, propolyne, butylene, benzene, xylene, gasoline, synthetic natural gas, No. 2 fuel oil and residual fuel oil. As by-products, hydrogen gas and pyrolysis fuel oil (PFO) are produced. In addition to naphtha cracker heaters, crude oil heaters and steam superheaters, the plant has two watertube boilers each capable of producing 300 000 lb/h of steam at 1500 psig to supply compressor drive turbines. Electricity is purchased from Ontario Hydro.

- A 1982 consultant's study looked into the feasibility of cogeneration alternatives using gas turbines and steam turbines, with none inherently economically feasible.

- The only major change to the plant since 1982 has been the addition of a third conventional boiler, not for capacity reasons but for operating flexibility. The plant has an overabundance of low level steam which limits the need for cogenerated steam.

- Recently the Company carried out an in-house review of cogeneration, utilizing the 1982 study base data. The same conclusion of lack of financial viability was arrived at. The general state of oil prices does not justify most conservation projects at this time.

- Energy conservation investments are not given any special status. Like other investments, they are subject to the one-year payback rule for small projects and the two-year rule for large--over $500,000--projects. Even the two-year rule is being squeezed so only the best projects get funded. Energy projects typically show three- to six-year paybacks.

- Cogeneration, if viable, would require some two years to plan; construction would have to be tied-in with production facility shutdowns; it would require an energy exchange agreement that may be timely to negotiate; it would have to consider the plant's steam balance, especially if the product mix were to change; but otherwise would not present an implementation problem. And, of course, viability at this time would require a capital grant component or higher buyback rates. We would want to burn PFO as the main fuel in any cogeneration facility.

Domtar Inc., Kraft and Board Division, Red Rock,
Mr. John Steer, Superintendent of Engineering, 807-886-2211

- The pulp and paper mill purchases all its electricity, a steady monthly demand of above 45 MW. The process steam load is between 400 000 and 600 000 lb/h. At the time of cogeneration study in 1981 the Company was installing a new high pressure waste fuel-fired boiler; this would be a major capital cost saving if cogeneration were subsequently considered. According to the study, the most feasible scheme was a 14.1 MW turbine generator passing virtually all of the 900 psi steam produced by the new black liquor boiler, at a total cost of about $5 million. If purchased power prices were to escalate in line with gas prices, the cogeneration scheme would have an after tax rate of return of 11%.

- In 1985 consultants for Ontario Hydro took another look and examined seven alternatives, with the preferred one being a 29 MW back-pressure unit or a new gas-fired high pressure boiler which would replace an existing low pressure boiler. Capital costs ranged from $770 to $943/kW with suggested payback periods ranging form 9 to 11 years. A 20-MW cogeneration facility would have an impact on northwestern Ontario's power system.

- Mr. Steer indicated that as terms of reference Company investments are expected to yield 20% on a discounted cash flow basis. At the same time, certain types of investments, environmental, for example, are made without reference to rate of return. However, an energy-related investment would have to be subject to financial criteria.

- Each year a five-year plan is prepared that identifies capital projects over $1 million; the annual capital budget also includes small projects. Cogeneration has never made it to the plan stage because of its lack of viability.

- Buyback rates are of no concern since Domtar would use all the electricity generated; however, a project with one generator would require back-up so that standby charges would be a factor. Straight forward capital incentives would be the easiest way to assist in making cogeneration happen.

Westinghouse, Hamilton, Mr. Lindsay Scott, Marketing Engineer - Steam Turbines, 416-528-8811

- Mr. Scott stated that at present there is almost no market interest in Canada for cogeneration equipment. Westinghouse manufacturers steam and gas turbines in Hamilton, mostly in the 300 MW and up range and sells to the United States and other countries. The only potential Westinghouse installation may take place in the Ottawa Valley--an 11 MW waste-wood-fired facility.

- In contrast, the US market is extremely active; cogeneration and solid waste plants have benefitted form PURPA (the Public Utility Regulatory Policies Act). This legislation has tended to deregulate the electric power generation industry by allowing small power producers access to guaranteed markets at utility 'full avoided cost' rates of revenue.

- In Canada all studies, including our own, show that basically the rates are still too low; in the US buyback rates of 7.5¢ US exist. This is the dilemma--our utility rates are low, which is beneficial to society, but at the same time these rates inhibit the development of certain energy self-sufficiency initiatives.

- In northwestern Ontario, where a number of cogeneration candidates are located (pulp and paper mills), the electricity system is smaller and probably more costly so that cogeneration might show greater economic viability.

Rose Technology Group Limited (a subsidiary of Consumers' Gas), Mr. Frank Dixon, Director of Business Development, 416-487-1301

- The Rose Technology Group is in the energy management and investment business, primarily dealing with large buildings such as institutions, offices and apartments. Typical equipment would be reciprocating engines and gas turbines with capacities under 2 MW. The Company views cogeneration as one of a number of potential energy conservation investments.

- The market interest for cogeneration in Ontario--in small applications--is almost nonexistent at present. Lack of economics is the reason. Opportunities with less than a five-year payback are hard to find, considering the differential between gas and electricity prices, which is the driving force of the market.

- The cogeneration decision is, to a large extent, based on what fuel prices, and the relationship between the prices of various fuels will do in the future. A short payback period is demanded because of the risk attached to being wrong about future price movements. A conducive environment for development of cogeneration requires stable fuel prices for four to five years to minimize risk.

- Barriers to implementation of small scale cogeneration in buildings include (1) the risk factor, (2) unfamiliarity with the concept, and (3) the unclear role of the utility.

- Risk. The government could assist by, for instance, fixing fuel prices in cogeneration transactions for a period of time to allow the investment threshold to be reached. The Ontario Energy Board could play a role here. Direct fuel purchase from suppliers by large customers, using long-term contracts and negotiated escalators, would help to spread risk over a longer period of time.

- Familiarity. Large building operators have neither the knowledge nor the resources, nor the confidence to enter the field. In the US there are companies dedicated to energy management, allowing for the spreading of required expertise over a number of sites. This kind of service industry is still in its early infancy in Canada.

- Utility. The Provincial utility's attitude, as a corporation, has been unclear because the principal focus of its planning and construction activity since the early seventies. Small technologies such as cogeneration have so far not received enough attention; this is now changing, but slowly.

  Specifically, the utility must recognize that small cogenerators do not have the time to negotiate contracts: ready and practical standards, rules and procedures should be available so that the small producer knows what to do. The utility should also have the capacity to overcome any objections of its distributors. And natural gas should be recognized as an appropriate cogeneration fuel; biomass for cogeneration in an office building is impractical. In general, once the attitude of the utility is more pro-cogeneration, implementation would occur naturally.